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IN THE

Supreme Court of the United States

October Term, 1982

PAUL P. and LYNN T. BROUNTAS,
Petitioners,

v.

COMMISSIONER OF INTERNAL REVENUE,
Respondent.

CRC CORPORATION,
Petitioner,

v.

COMMISSIONER OF INTERNAL REVENUE,
Respondent.

CONSOLIDATED APPENDIX TO PETITIONS FOR WRITS OF CERTIORARI TO THE UNITED STATES COURTS OF APPEALS FOR THE FIRST CIRCUIT (BROUNTAS) AND FOR THE THIRD CIRCUIT (CRC CORP.)

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United States Court of Appeals

FOR THE FIRST CIRCUIT

No. 81-1840

PAUL P. BROUNTAS, ET AL.,
Petitioners, Appellees,

v.

COMMISSIONER OF INTERNAL REVENUE,
Respondent, Appellant.

No. 81-1877

PAUL P. AND LYNN T. BROUNTAS,
Petitioners, Appellants,

v.

COMMISSIONER OF INTERNAL REVENUE
Respondent, Appellee.

CROSS-APPEALS FROM THE UNITED STATES TAX COURT
[Hon. Cynthia H. Hall, *Judge*]

[73 T.C. 491 (1979)]
[74 T.C. 1062 (1980)]

Before Campbell and Breyer, *Circuit Judges*, and Pettine,* *Senior District Judge*.

George L. Hastings, Jr., Attorney, Tax Division, Department of Justice, with whom *Glenn L. Archer, Jr.*, Assistant Attorney General, *Michael L. Paup* and *Ann Belanger Durney*, Attorneys, Tax Division, Department of Justice, were on brief, for Commissioner of Internal Revenue. *Thomas B. Rutter*, for Paul P. Brountas, et al.

September 28, 1982

BREYER, *Circuit Judge*. In this "tax shelter" case, we are asked to determine the propriety of certain deductions taken by a limited partner in an oil-and-gas drilling partnership. There is little question that subsequent changes in the law have made deductions similar to those at issue here improper for individual taxpayers. *See* 26 U.S.C. § 465 (Supp. IV 1980) (the "at risk" provisions). But, under the law as it stood when the deductions were taken, which is the law we must apply, the propriety of the deductions is a complicated and unsettled question. The Tax Court's opinion from which this appeal was taken holds that the deductions were proper. *See* 73 T.C. 491 (1979). Yet, the Fifth Circuit, in a different case but on nearly identical facts, determined that they were not. *Gibson Products Co. v. United States*, 637 F.2d 1041 (1981). Having reviewed both of these decisions, as well as the briefs filed and various cases and authorities, we

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* Of the District of Rhode Island, sitting by designation.

find as did the Fifth Circuit (but for somewhat different reasons) that the deductions here were improper.

I

This case arises out of the activities of a Texas limited partnership known as "Coral I." The partnership was organized in 1972, and was set up to explore and develop "oil and gas" property. The case involves two investors in Coral I. One is CRC Corp., which was both a limited and general partner. The other is Paul Brountas, one of several limited partners in Coral I. Brountas contributed $10,000 in 1972 and $1,000 in 1973. He and his wife (who filed a joint return with her husband) filed a petition in the United States Tax Court contesting a notice of deficiency in their return for 1972. The Tax Court found in favor of the petitioners. The Commissioner has appealed. Brountas has also appealed from one part of the Tax Court's decision. The appeals in this circuit concern Brountas and his wife but not CRC.

The Coral I partnership worked in essentially the following manner: At the outset, partners would contribute money (as Brountas did in the amount of $10,000). This money would then be used to buy participations in what looked like promising "oil and gas" ventures. These ventures were invariably set up by CRC officials, and then sold in fractional interests to various CRC-managed partnerships (such as Coral I) and to CRC on its own account. In each case, a venture encompassed a package of several (typically three) oil and gas leasehold interests, or "prospects." These prospects (leaseholds) were owned by an "operator"—an entrepreneur unrelated to CRC who wanted to develop the prospects but lacked the money to do so. The investors had the money at a time when it was apparently difficult to obtain in the oil and gas

industry; they were in a position to strike advantageous bargains.

The bargains followed a uniform pattern. The operator would agree to convey to the investors a set of "oil and gas" leaseholds and would agree to drill a test well on each. The test well was often an expensive undertaking because CRC officials insisted that the operator agree to complete the well no matter how difficult this proved to be. In return, the investors agreed to pay the operator a "total" contract price. This price consisted of a "lease purchase price" and a "drilling contract price," corresponding to the two parts of the operator's agreement. Each of these component prices was apparently negotiated separately with the operator by someone on CRC's behalf. The Tax Court found, and the government does not contest, that the two prices were each the result of arms-length bargaining and represented reasonable charges for the leaseholds and obligations in question.

The investors, however, did not pay the total price in cash. Rather, they paid the contract price with what the Tax Court found amounted to 40 percent in cash and 60 percent in a "nonrecourse" note. The "nonrecourse" note bore interest and was payable "on demand" after a certain time (usually about five years). It was "secured" by a percentage of oil and gas production from the underlying prospects, by a percentage of the leaseholds themselves, and by some of the equipment used. And, it provided that payment on the notes would be made out of production once production began. Despite these assurances, however, it was quite clear to all concerned that neither principal nor interest on a note would ever be paid if the prospects in a given venture all proved to be nonproducers. The investors were not personally liable on the notes; the operators could look to no property other than that securing the notes for payment; and all of that

property would be essentially worthless if the wells proved to be dry. As a practical matter, the notes would be paid out of production or not paid at all.

The agreement between the investors and the operator provided the operator with one further potential source of compensation for drilling the test wells—a "development option." If a well proved successful, the agreement allowed the operator to gain an "equity" interest in its production by entering into a "completion joint venture" with the investors. To exercise this "development option," the operator would have to agree to "complete" the test well to obtain production and to reimburse the investors for certain previous expenses. The operator and investors would then share all future costs and production in a specified ratio (subject to certain additional restrictions and conditions not relevant here).

The limited partners believed they had invested in a leveraged "tax shelter." This type of shelter provides an investor with tax deductions greater in amount than the cash that he initially provides for the investment. These extra deductions can be subtracted from the investor's ordinary income, thus "sheltering" some of his ordinary income from tax. Of course, these extra deductions may some day be offset when the investor must recognize "income" though he receives no payment. But this day of reckoning is in the future, and in the meantime the government has provided the investor at least with what is effectively an interest-free loan of the dollars that it otherwise would have taxed away. *See* Harrell & Stricoff, *Overview of an Oil and Gas Tax Shelter*, 28 Oil & Gas Tax Q. 496, 496 (1980).

We can illustrate how the promoters and investors thought this shelter would work by using the facts of this case in simplified form. Assume the operator conveys a package of prospects to investors for $250,000 and

agrees to drill test wells on each prospect for another $750,000. The investors, in turn, agree to pay the "total contract price" of $1,000,000 with $400,000 in cash and $600,000 in a nonrecourse note payable out of production and secured (as indicated above) by production, leaseholds, and equipment. The operator and the investors further agree to allocate $100,000 of the cash and $150,000 of the note to the "purchase price" of the prospects, and $300,000 of the cash and $450,000 of the note to the "drilling contract price." In short, they agree that the same note/cash ratio as applies to the total price shall also apply to the two component prices. For simplicity, assume that there is only one investor, a partnership called Coral I, and that a (hypothetical) limited partner called Brountas has contributed cash equal to one percent, or $4,000, of the partnership's initial cash capital. Assuming these numbers, Brountas' argument amounts to a claim that he is entitled to deduct $7,500 as expenses. This figure—$7,500—equals one percent (Brountas' share) of the total "drilling contract" price.

Brountas' argument begins with the fact that the cost of drilling an oil well is an immediately deductible expense. This is so because the Internal Revenue Code allows taxpayers (who make the proper election) to deduct all "intangible drilling and development costs" (or IDC's) in the year incurred. 26 U.S.C. § 263(c)(Supp. IV 1980); Treas. Reg. § 1.612-4(a)(1965). The Code treats other expenses less favorably. The cost of machinery and equipment must be capitalized and depreciated. The cost of acquiring leaseholds is not immediately deductible, but instead becomes part of the investor's tax "basis" and must be recovered gradually through the depletion allowance or on final disposition of the property as an offset against "amount realized." But unlike these costs, the "intangible" costs of drilling and developing a

well, such as "wages, fuel, repairs, hauling, supplies . . . [and] the cost to [the investors here] of any drilling or development work . . . done for them by contractors under any form of contract," Treas. Reg. 1.612-4(a)(1965) are immediately deductible.

Brountas thus claims that the partnership incurred what (in our example) amounts to $750,000 in IDC's in its first year. This expense consists of its payment to the operator (in return for a promise to drill) of $300,000 cash and $450,000 in nonrecourse notes. Brountas believes that the partnership, an accrual base taxpayer, can accrue as an expense in 1972 the future obligation to pay money that the notes represent. And, as a one percent partner, Brountas seeks to deduct one percent of the partnership's total IDC expense, or $7,500.

Brountas is aware that he must first demonstrate that he has a "basis" in the partnership of at least $7,500. The Internal Revenue Code limits the share of partnership losses that a partner may deduct to the extent of the partner's "basis" in the partnership. 26 U.S.C. § 704(d) (1976). This basis includes the money or other property that the partner has contributed to the partnership. 26 U.S.C. §§ 705 & 722 (1976). But, in our example, that amounted only to $4,000. How then can Brountas deduct $7,500? Brountas points to § 752(a), which states that "[a]ny increase in a partner's share of the liabilities of a partnership . . . shall be considered as a contribution of money . . . ." The nonrecourse notes, he explains, are liabilities of the partnership. Hence, his basis increases by his share of the notes, or $6,000, and thus § 704 does not limit his right to deduct his proportionate share of the IDC expense.

The Commissioner of Internal Revenue disagrees with Brountas. His major point of disagreement concerns treatment of the nonrecourse notes. The Commissioner

argues that the notes do not represent liabilities sufficiently certain and definite to warrant their accrual as IDC expenses of the partnership or to warrant counting them as a "liability"of the partnership for "basis" purposes under § 752(a). The Fifth Circuit essentially accepted the Commissioner's views in *Gibson, supra.*

Brountas, the taxpayer, can prevail only if 1) his partnership basis increased sufficiently to allow him to deduct his full proportionate share of partnership expenses, and 2) the partnership's accrual for tax purposes—and hence the partners' deduction—of the total (cash plus noncash) "cost" of the drilling contract were proper. We shall address each of these issues in turn.

II

As previously mentioned, a partner's basis in a partnership is defined to be the amount of money he contributes to the partnership. 26 U.S.C. §§ 705, 722 (1976). But since "[a]ny increase in a partner's share of the liabilities of a partnership . . . shall be considered as a contribution of money," 26 U.S.C. § 752(a)(1976), it is clear that when the partnership itself incurs a liability, a partner's basis ordinarily rises by his share of the liability. *See generally* 1 W. McKee, W. Nelson & R. Whitmire, *Federal Taxation of Partnerships and Partners* § 7.01[1] (1977). In an ordinary (*i.e.*, nonlimited) partnership with recourse indebtedness, partners are personally liable for partnership debts. For this reason, "the practice generally has been to treat the indebtedness of the partnership as the indebtedness of each member of the partnership according to his proportionate share of the debt. Theoretically, each partner (other than a limited partner) is liable for the entire partnership indebtedness. However, because of the right of contribution among the partners, the partners have been considered as economically burdened

only with their share of the partnership debt. The share of partnership debt was treated under the 1939 Code as a contribution by the partners and included in the bases of their partnership interests. Section 752 of the 1954 Code, in substance, continues [this] practice." 6 *Mertens Law of Federal Income Taxation* § 35.45 (1968); *See* 1 W. McKee, W. Nelson & R. Whitmire, *supra*, at § 8.01[1].

A limited partner, however, is liable for debts of the partnership only to the extent of the money he has contributed or is obligated to contribute. Thus, regulations provide that "a limited partner's share of partnership liabilities shall not [in general] exceed the difference between his actual contribution . . . and the total contribution which he is obligated to make . . . ." Treas. Reg. § 1.752-1(e)(1956). But, where no partner is *personally* liable on a partnership liability (*e.g.*, nonrecourse indebtedness), the regulations provide that "all partners, including limited partners, shall be considered as sharing such liability . . . in the same proportion as they share the profits." *Id.* The question before us here is whether the nonrecourse indebtedness in this case amounts to "liability" for purposes of § 752(a). We believe that it does not.

A

Were it not for a special "production payment" section of the Code, § 636, which we shall discuss in subpart B below, this question would not be difficult. The liabilities that investors typically are allowed to include in basis are relatively definite liabilities such as those upon which a lender might rely when he advances money to a borrower. In a typical loan transaction, a lender advances money or property only when either the borrower has personally promised to pay him back, or when there is adequate security to guarantee repayment, or both. Thus,

the borrower does not take the loan into income, for it is offset by the obligation to repay. And, the amount of this obligation constitutes all or part of the borrower's "basis" in the property to which the repayment obligation attaches. *See generally* Fielder, *Drilling Funds and Nonrecourse Loans—Some Tax Questions*, 24 Oil & Gas L. & Tax Inst. 527 (1973). As long as the obligation is secured by property of at least equivalent value, courts have been willing to treat even "nonrecourse" liabilities as sufficiently likely to be paid to warrant their inclusion in an investor's basis. "[T]he reality [is] that an owner of property, mortgaged at a figure less than that at which the property will sell, must and will treat the conditions of the [nonrecourse] mortgage exactly as if they were his personal obligations." *Crane* v. *Commissioner*, 331 U.S. 1, 14 (1947).

When, however, an obligation to pay is both nonrecourse *and* not secured by property of at least equivalent value, courts have been reluctant to consider it a liability that increases an investor's basis. Thus, cases subsequent to *Crane* have found it proper to include nonrecourse debt in basis only insofar as the value of property securing the debt is equal to or greater than the face amount of the debt. *See, e.g., Estate of Franklin* v. *Commissioner*, 544 F.2d 1045, 1048-49 (9th Cir. 1976); *Gibson Products Co.* v. *United States*, 460 F. Supp. 1109, 1117-19 (N.D. Tex. 1978), *aff'd on other grounds*, 637 F.2d 1041 (5th Cir. 1981); *see also* Rev. Rul. 77-110, 1977-1 C.B.58; Adams, *Exploring the Outer Boundaries of the* Crane *Doctrine; An Imaginary Supreme Court Opinion*, 21 Tax L. Rev. 159, 165-66 (1966); *cf. Crane* v. *Commissioner*, 331 U.S. at 14, n.37 ("if the value of the property is less than the amount of the mortgage, . . . a different problem might be encountered"). A further line of decisions holds that highly contingent or speculative obligations are not

includible in basis before the uncertainty surrounding them is resolved. Thus, in *Lemery* v. *Commissioner*, 52 T.C. 367, 377-78 (1969), *aff'd on other grounds*, 451 F.2d 173 (9th Cir. 1971), the court held that an obligation to pay part of the purchase price of a business out of "net profit" was too contingent to be included in the purchaser's basis. Similarly, in *Denver & Rio Grande Western Railroad Co.* v. *United States*, 505 F.2d 1266, 1269-70 (Ct. Cl. 1974), the court refused to allow the railroad taxpayer to include in its basis advances by a customer (used to build a "spur line") which were repayable only out of proceeds from shipping above a certain annual tonnage for ten years.

These decisions are consistent, for payment of a nonrecourse obligation is unlikely to be speculative to the extent that it is secured by property with a determinable value. Moreover, these decisions *cannot* be based upon a belief that the *value* of a nonrecourse note is limited to the value of the property that secures it, for a $1 million nonrecourse note secured by a $200,000 building is, other things being equal, considerably more valuable than a $200,000 note secured by the same building. (The note's value will reflect the fact that the building's value might rise, in which case the holder of the first note will receive more money than the holder of the second.) Therefore, these decisions must reflect an administrative fact—namely, the fact that it is simpler, when faced with obligations to pay that are highly uncertain, to wait and see if the contingency occurs. If it does not occur, the obligations need never enter basis, for they do not represent any obligation to pay. If it does occur, the extent of the monetary obligation will be reasonably capable of calculation, and any change in basis (where appropriate) can then be determined.

Given these cases and their apparent rationale, it is not surprising that the district court, facing this issue in *Gibson Products Co. v. United States*, 260 F. Supp. 1109, 1115-17 (N.D. Tex. 1978), held that notes virtually identical to those at issue here were too contingent to be included in basis. Similarly, the Tax Court in the case at bar wrote that, leaving aside § 636 (the special section to be discussed in subpart B below), it is "highly doubtful that [the nonrecourse notes] . . . or any similar nonrecourse highly contingent obligation would be a 'liability' for purposes of section 752(a) [governing basis in a partnership]." 73 T.C. at 559. The obligations here, unlike recourse notes, represented (as a practical matter) a promise to pay only if oil was found. They seem less like the repayment obligation that typically accompanies a recourse loan than like a device for sharing business risks —the risks that accompany oil explorations.

In sum, if these obligations are too contingent or speculative to warrant inclusion in an individual investor's basis, we see no reason here why they should nonetheless count as basis increasing § 752 partnership "liabilities." Rather, we believe the views of the Commissioner, the Tax Court, and the *Gibson* district court to the contrary are correct.

B

We now turn to the question of whether § 636 requires a different result. That section states in subsection (a) that a "production payment that is carved out of a mineral property shall be treated . . . as if it were a purchase money mortgage loan and shall not qualify as an economic interest in the mineral property." *See also* 26 U.S.C. § 636(b)(1976)(*retained* production payment). Brountas and the Tax Court reasoned as follows: 1) The nonrecourse obligations here amounted to "production

payments." 2) Under § 636 production payments are to be treated like "loans." 3) True loans involve a lender who expects the borrower's obligation to be paid and are typically treated as a liability that increases partnership basis. 4) Hence, the obligations here should be added to Brountas' basis.

To understand the flaw in this reasoning, one must understand both what a production payment is and the purpose underlying § 636. Essentially, a production payment is a *limited* right to receive revenue from the production of mineral in place. The right may be limited by a dollar amount, by an amount of the mineral, and by a period of time. *See* Treas. Reg. 1.636-3(a)(1)(1973); Berry, *Section 636—Production Payments*, 25 Inst. on Oil & Gas L. 389 (1974). Thus, a production payment might consist, for example, of a right to receive revenue from one-half annual production from a specified property for, say, ten years, or, say, until receipts total $100,000. It might consist of a right to receive the revenue from the first four hundred thousand barrels of oil produced. But a right that is not so limited—a right to receive revenue in perpetuity or until the mineral is exhausted—would be a "royalty," not a "production payment."

An obligation must meet several other technical requirements to qualify as a "production payment." *See* Treas. Reg. § 1.636-3(a)(1)(1973); Berry, *supra*. In fact, the Fifth Circuit in *Gibson Products Co. v. United States*, *supra*, resolved the § 636 problem we face here by holding that notes like these failed to meet one of these other requirements—namely, the requirement that the obligation be payable *solely* out of production. *See Anderson v. Helvering*, 310 U.S. 404, 412-13 (1940). It reasoned that the obligations were secured not only by production but also by the leaseholds themselves and by the salvage value of equipment used on the property.

The Tax Court in the case at bar, however, found that these other sources of security lacked economic significance. And, the circuits appear to be split on the question of whether the existence of other security that is economically insignificant deprives an obligation of its status as a "production payment." *Compare Christie v. United States*, 436 F.2d 1216 (5th Cir. 1971) *with Standard Oil Co. (Indiana) v. Commissioner*, 465 F.2d 246 (7th Cir. 1972); *see also* Treas. Reg. § 636-3(a)(2)(1973). We believe that it is not necessary to enter this controversy, for even if the obligation here at issue is a production payment, we do not believe that § 636 changes the result.

Next, it is important to understand the purpose of § 636. When it enacted § 636, Congress feared that by creating "production payments," owners of oil wells could secure certain unjustified tax advantages. The precise way in which production payments achieved these advantages varied, depending, for example, on whether the payment was "carved out" by the property owner and transferred to one who in return provided services, money, etc., or whether it was "retained" by the seller when he sold the property. But, one can intuitively grasp the sort of problem that Congress saw by considering the following:

Suppose that Smith assigns to Jones the butcher (in return for meat) a 'right' to $20 worth of Smith's future income. That income, when received by Smith, despite the 'assignment' is first taxed as Smith's income and then again as Jones'. Suppose that Smith assigns $100,000 of future rents in Smith's apartment house to Jones in return for services. Again, the $100,000 rent is taxed as Smith's income first. Suppose Jones has *sold* the apartment house to Smith for $1 million taking $900,000 in cash and the remainder in the form of a 'right' to the first $100,000 of rent. Again, the rent is taxed as *Smith's* income, for

Jones is considered to have *loaned* Smith the extra $100,000 needed to pay the full $1 million and Smith is considered to be paying back this loan out of the apartment house rent. *See Helvering* v. *Eubank*, 311 U.S. 122 (1940); *Helvering* v. *Horst*, 311 U.S. 112 (1940). These examples would have worked out differently, however, before § 636 if we were dealing with *oil*, rather than apartment houses, for an assignment of what might have looked like future income (or rents) or a retained right to that income—if properly characterized as a "production payment"—was considered to be the income *only* of the person who received (or retained) the payment. That person was considered to possess an "economic interest" in the producing property; the income that it produced (that went to him) would be considered his income alone, not that of others who might possess "economic interests" in the property. Hence, if Smith paid Jones for services with an oil "production payment" (rather than a right to a share of apartment house rents) the payments, as they flowed in, would *not* be considered part of Smith's income. And, if Jones sold Smith for $1 million an oil property (rather than an apartment house), retaining a $100,000 production payment (instead of a right to $100,000 of rents), the $100,000 as it flowed in would *not* be considered Smith's income; that is to say, it would *not* be treated as if Jones had loaned Smith $100,000 which was being paid back out of income that went to Smith.

These examples illustrate the essence of what Congress felt was wrong. Congress felt that the oil property owner or buyer should be treated basically like the apartment house owner or buyer. He should not be allowed to pay for services or pay for his property (by creating a production payment) with what Congress viewed as "pre-tax" dollars. Indeed, Congress noted that tax advisors were taking advantage of the comparatively favor-

able tax treatment given production payments to structure what were known as "ABC transactions." An oil property owner (A) would sell the property to B for some cash, reserving a production payment for the rest of the purchase price. A would then sell the reserved payment to C, a financial (or preferably a tax exempt) institution. A would thus receive the whole price in cash at once, while the buyer B, in effect, would pay off the loan from C to A with "pre-tax" oil revenue dollars (taxed as income to C and *not* taxed as income to B). *See generally* H.R. Rep. No. 91-413 (part 1), 91st Cong., 1st Sess. 140 (1969); Berry, *supra*, at 403.

The way Congress dealt with this problem in § 636 was to require that some (but not all) production payments be treated like "loans." *See* 26 U.S.C. § 636(a) (carved-out exploration or development production payment not treated as a loan). That treatment simply removed what had previously made the production payment unique, the special "income attribution" that went with it. As the Tax Court explained in this case:

> When a production payment is treated as a loan, it is treated "as if" the recipient (holder) of the production payment loaned money, equipment, or services to the creator of the production payment, in return for which the recipient received rights under the production payment. When production is realized and the holder of the production payment is paid, the payments are treated as repayment of the liability created by the loans.

73 T.C. at 569-70. Thus, after § 636, the transferor of the production payment or buyer of the property (Smith in our examples) will normally be charged with the income used to satisfy the production payment.

Congress, then, was concerned with the special "income attribution" effect of production payments. It changed that effect in § 636 so that, for example, the buyer of the oil property would be treated like the buyer of the apartment house. This was its object in saying that a "production payment" should be treated as a "mortgage loan" (§ 636(a)) or a "purchase money mortgage loan" (§ 636(b)).

Given this background, the Tax Court and Brountas cannot draw from 1) § 636's use of the word "loan" and 2) the fact that loan repayment obligations are *normally* not highly contingent or speculative, the conclusion that § 636 prohibits treating *any* production payments for basis purposes as highly contingent or speculative. For one thing, the "income attributive" purposes of § 636 do not require treating highly speculative or contingent payment obligations as if they were not highly speculative or contingent. Rather, those purposes have nothing to do with the effect that the speculative or nonspeculative quality of the obligations has on basis. And, treating highly speculative or contingent payment obligations in the presence of § 636 just as they would be treated in its absence would not, as far as we know, interfere with any of § 636's stated purposes.

For another thing, the language of § 636 is broad enough to allow this result. That language states that a "production payment" is to be treated as a "mortgage loan" or as a "purchase money mortgage loan." The language is general, rather than precise. As pointed out by the Tax Court, it means that the right to money under the payment is viewed as if it were received under an obligation to repay a loan. Thus, the language is best taken as a general instruction to view the whole transaction in a way that carries out the section's purpose. In any event, one can consider the notes—the payment obli-

gations—at issue here as if they were "loan repayment" obligations (for income attributive purposes) and at the same time consider them as highly speculative or contingent payment obligations (for basis purposes). The Fifth Circuit has specifically held that what it characterized as a "mortgage loan" is not "an indebtedness within the meaning of the Code." *Guardian Investment Corp.* v. *Phinney*, 253 F.2d 326, 331 (5th Cir. 1958).

Further, the Treasury Regulations offer mild support for our interpretation of § 636. Treas. Reg. 1.636-1(a)(1)(i)(1973) states in part that:

> [I]n the case of a transaction involving a production payment treated as a loan pursuant to this section, the production payment shall constitute an item of income (not subject to depletion), consideration for a sale or exchange, a contribution to capital, or a gift if in the transaction a debt obligation used in lieu of the production payment would constitute such an item of income, consideration, contribution to capital, or gift, as the case may be.

This regulation suggests that the "debt obligations" (which production payments are to be "treated as") should continue to be treated differently in different circumstances, just as they were before § 636. Indeed, there is simply no reason to believe that Congress in using § 636 to close what it saw as one tax loophole wished to open another by erasing the tax distinction between those payment obligations that are highly contingent or speculative and those that are not. The Fifth Circuit refused to interpret § 636 "to produce such an absurd result." *Gibson Products Co.* v. *United States*, 637 F.2d at 1052.

Finally, the single argument that gives us pause consists of the claim that where production payments are at

issue, highly contingent or speculative repayment obligations should not be distinguished from others because production payments are *always* speculative. One can never be certain whether there is sufficient oil to meet the payment. We do not consider this argument determinative, however, because one can still distinguish among degrees of uncertainty; a right to collect funds from a property where oil has not yet been found would seem far more speculative than rights secured by the production of existing wells. (In fact, the Tax Court wondered how a right payable from a yet unexplored property could even qualify as a § 636 production payment given the Treasury Regulation's requirement that the "right must have an expected economic life (at the time of its creation) of shorter duration than the economic life of one or more of the mineral properties burdened thereby," Treas. Reg. § 1.636-3(a)(1)(1973). But, the Commissioner did not argue this point.)

In sum, we do not believe that § 636 changes the tax basis treatment that Brountas' nonrecourse notes would receive without it. Without that section, Brountas' basis in the partnership would not increase to reflect the value of the nonrecourse notes. Hence, in this case he did not have the right to make certain of the deductions he claimed on his tax return.

III

We turn now to the second question that the Commissioner has raised, namely, whether the partnership's accrual for tax purposes (and hence the deduction by the partners) of the total "cost" of the drilling contract was proper. In our view, the partnership could not accrue for tax purposes the noncash portion of that "cost." We believe that the Fifth Circuit dealt with this issue correctly in *Gibson*, and we adopt its reasoning, set forth at 637 F.2d at 1046-47.

In essence, the same facts that make the nonrecourse notes too speculative or contingent to enter Brountas' basis in the partnership make it improper for the partnership to accrue the expense that it claims transfer of the notes to the operator represented. That is to say, because Coral I's note would effectively be paid only from the proceeds of any oil and gas delivered, "all the events" necessary to determine the fact and amount of liability had not yet occurred. Accordingly, the accrual of the liability as an expense was not yet proper. *See Brown v. Helvering*, 291 U.S. 193, 200-01 (1934); *United States v. Anderson*, 269 U.S. 422, 441 (1926); *Subscription Television, Inc. v. Commissioner*, 532 F.2d 1021, 1027 (5th Cir. 1976); *Denver & Rio Grande Western Railroad Co. v. United States*, 505 F.2d at 1270 (Ct.Cl. 1974); Treas. Reg. § 1.461-1(a)(2)(1957).

The fact that the Tax Court found that the notes had economic substance, *see* 73 T.C. at 545-46, does not change our result. A note may have economic substance yet be so contingent as not to warrant its accrual as a present expense. *See Brown v. Helvering*, 291 U.S. at 201 (accrual of expense improper where amount was uncertain, even though "[e]xperience taught" that there was "strong possibility" that some expense would be incurred); *Mooney Aircraft, Inc. v. United States*, 420 F.2d 400, 410 (5th Cir. 1969). Nor is our result affected by the Tax Court's finding that the combined value of the cash, notes, and development options transferred by Coral I were at least equal to the total contract prices, *see* 73 T.C. at 577-78, for the option could not be exercised unless oil was found; thus the development options were fully as contingent as the notes. An expense may be accrued only when the fact and amount of the liability can be determined "with reasonable accuracy," Treas. Reg. § 1.461-1(a)(2)(1957); the fact that the notes and options had

a fair market value of "at least" a given amount does not show whether (and if so, how much of) the liability they represent will ever be paid.

IV

The Commissioner raises two other issues in his appeal. First, he argues that Brountas should not be allowed to deduct on his tax return amounts representing the interest charge accruing on the nonrecourse notes. Our decisions in parts II and III thus far controls this matter. The accrued interest charges on the notes, insofar as relevant here, must receive the same tax treatment as the notes, for the reasoning of parts II and III applies to them, *mutatis mutandis*. Second, the Commissioner seeks review of the Tax Court's supplemental opinion, *see* 74 T.C. 1062 (1980), concerning the recognition of lease abandonment losses. However, the Commissioner states in his brief that, if this court agrees with his position on the "basis" and "deductibility" issues, his challenge to the supplemental opinion becomes moot. Hence, we do not consider it.

V

Finally, we turn to taxpayer Brountas' appeal from a separate part of the Tax Court's decision. Evidently, the individual leaseholds were divided into separate parts called "horizons." When a test well was drilled and turned out dry, a geologist would recommend whether to abandon the horizon or to abandon the entire leasehold. When an entire leasehold was abandoned, the taxpayer stopped paying "delay rentals" and presumably lost his right to the property. When only some horizons and not the entire leasehold were abandoned, however, the taxpayer continued to pay "delay rentals," presumably so that he would not lose his right to drill elsewhere on the

leasehold. The taxpayer nonetheless sought to deduct as a loss that part of his investment in a leasehold accounted for by abandoned horizons. The Tax Court refused to allow this deduction. And, since some of the investment was in cash, our previous discussion does not make the issue moot.

We reject the taxpayer's claim and we agree with the government and the Tax Court: it was improper to take abandonment losses for mere pieces of a leasehold. The law is clear. To be entitled to an abandonment loss, a taxpayer must show "an *intention* 'to abandon the property, coupled with an *act* of abandonment . . . .'" *Massey-Ferguson, Inc.* v. *Commissioner*, 59 T.C. 220, 225 (1972) (emphasis added). Where "delay rentals" were no longer paid, the Tax Court found such an "act" and allowed the loss deduction. Where the taxpayer continued to pay "delay rentals," however, the court found no such "act." The Tax Court in the case at bar noted:

> We believe that a geological determination of total worthlessness, coupled with the objective cessation of the payment of delay rentals, establishes that a mineral lease has been abandoned. There may be other ways in which an act of abandonment could have occurred—such as delivery to the lessor of a legally binding instrument disclaiming further rights under the lease—but we need not decide this because there is no evidence here of any irrevocable, definitive act of abandonment prior to letting the delay rental due date lapse without payment.

73 T.C. at 585.

We believe the Tax Court's decision on this point is correct. The mere determination that a stratum is worthless, even if made on the advice of geological experts, does not necessarily show abandonment. As long as the

investors continued to pay the delay rentals, they had the right to test other strata and even the purportedly abandoned stratum. "In a case such as this it would be more reasonable to fix the date of worthlessness as being the date when the parties refused to pay further rents . . . ." *A.T. Jergins Trust* v. *Commissioner*, 22 B.T.A. 551, 561-62 (1931), *rev'd on other grounds*, 61 F.2d 92 (9th Cir. 1932), *rev'd sub nom. Burnet* v. *A.T. Jergins Trust*, 288 U.S. 508 (1933); *see also Macon Oil & Gas Co.* v. *Commissioner*, 23 B.T.A. 54 (1931); *cf. Thor Power Tool Co.* v. *Commissioner*, 439 U.S. 522, 545-46 (1979) (disallowing a deduction for "excess" but not yet scrapped inventory with the comment: "There is also no reason why Thor should be entitled, for tax purposes, to have his cake and eat it too.").

In asserting their right to take "partial abandonment" losses, taxpayer refers us to the case of *A.J. Industries, Inc.* v. *United States*, 503 F.2d 660 (9th Cir. 1974). But we see nothing in that case which conflicts with the Tax Court's decision. To be sure, the Ninth Circuit indicated in *A.J. Industries* that the "subjective judgment of the taxpayer . . . as to whether the business assets will in the future have value is entitled to great weight . . . ." *Id.* at 670. But it did not say that a "business judgment" of worthlessness obviated the need for an affirmative act of abandonment. To the contrary, it referred to that requirement as settled law. *See id.* at 670-72. And, it upheld the challenged deductions (relating to the abandonment of a mine) because there *was* such an act (the execution of a salvage contract). *Id.* at 674.

The decision of the Tax Court is vacated and the cause is remanded for proceedings consistent with this opinion.

UNITED STATES COURT OF APPEALS
FOR THE FIRST CIRCUIT

No. 81-1840.

PAUL P. BROUNTAS, ET AL.,
Petitioners, Appellees,

v.

COMMISSIONER OF INTERNAL REVENUE,
Respondent, Appellant.

No. 81-1877.

PAUL P. AND LYNN T. BROUNTAS,
Plaintiffs, Appellants.

v.

COMMISSIONER OF INTERNAL REVENUE,
Defendant, Appellees.

JUDGMENT

Entered September 28, 1982

This cause came on to be heard upon cross-appeals from the United States Tax Court and was argued by counsel.

Upon consideration whereof, It is now here ordered, adjudged and decreed as follows: The decision of the Tax Court is vacated and the cause is remanded for further proceedings consistent with the opinion filed this day.

Each party to bear its own costs.

By THE COURT:

/s/ DANA H. GALLUP,
Clerk.

UNITED STATES COURT OF APPEALS
FOR THE FIRST CIRCUIT

No. 81-1840

PAUL P. BROUNTAS, ET AL.,
Petitioners, Appellees,

v.

COMMISSIONER OF INTERNAL REVENUE,
Respondent, Appellant.

No. 81-1877

PAUL P. AND LYNN T. BROUNTAS,
Petitioners, Appellants,

v.

COMMISSIONER OF INTERNAL REVENUE,
Respondent, Appellee.

Before COFFIN, *Chief Judge*, CAMPBELL, BOWNES & BREYER, *Circuit Judges*, PETTINE*, *District Judge*.

ORDER OF COURT

Entered November 17, 1982

Upon consideration of the "Petition for Rehearing or Rehearing En Banc", which document was submitted to the members of the panel and to the judges of the Court who are in regular active service; and

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* Of the District of Rhode Island, sitting by designation.

The judges of the panel having voted to deny the petition for rehearing, and the judges of the Court who are in regular active service having voted against the rehearing en banc,

It is ordered that said application for hearing en banc is hereby denied.

By THE COURT:

DANA H. GALLUP, Clerk.

By: Francis P. Scigliano
Chief Deputy Clerk.

UNITED STATES COURT OF APPEALS
FOR THE THIRD CIRCUIT

No. 82-3009

CRC CORPORATION,

Appellant

v.

COMMISSIONER OF INTERNAL REVENUE

No. 82-3010

CRC CORPORATION

v.

COMMISSIONER OF INTERNAL REVENUE,

Appellant

(Tax Court No. 8497-96)

ON APPEAL FROM THE UNITED STATES TAX COURT

Argued: September 15, 1982
Before: GIBBONS, WEIS and SLOVITER, *Circuit Judges*
(Opinion Filed: November 16, 1982)

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OPINION OF THE COURT

GIBBONS, *Circuit Judge.*

The Commissioner of Internal Revenue appeals from a decision of the United States Tax Court with respect to the federal income tax liability of CRC Corporation for the calendar year 1972. The taxpayer cross-appeals from that decision to the extent that it disallowed deduction of certain abandonment losses. At issue in the Commissioner's appeal is the tax treatment of deductions by a limited partner in an oil and gas drilling partnership. The Tax Court held that the deductions taken by the taxpayer were proper under the law applicable in 1972.[1] 73 T.C. 491.

We reverse that holding. The Tax Court also held that the taxpayer could deduct abandonment losses for abandonment of only parts of an oil and gas leasehold. We affirm that holding.

The Tax Court decision which we review disposed of the tax liability of CRC Corporation and that of

1. The deductions would now undoubtedly be improper. *See* 26 U.S.C. § 465 (Supp. IV 1980).

another limited partner, Paul P. Brountas. Brountas appealed to the Court of Appeals for the First Circuit, which, on September 28, 1982, concluded that the Tax Court erred in permitting the deduction of drilling expenses in excess of the limited partner's actual investment in the partnership, but did not err in disallowing claimed abandonment losses. *Brountas v. Commissioner*, Nos. 81-1840, 81-1877, Slip op. (1st Cir. Sept. 2, 1982). The facts in *Brountas* are identical with those in this case. In *Gibson Products Co. v. United States*, 637 F.2d 1041 (5th Cir. 1981), the court, dealing with a different limited partnership, but a fact pattern otherwise indistinguishable, reached the same conclusion with respect to deductibility of partnership expenses in excess of a limited partner's investment.

Brountas, Gibson Products, and this case all involve so-called leveraged leases. Under these arrangements an oil and gas operator assembles a package of leasehold interests, which he conveys to a limited partnership, for a cash payment and a nonrecourse note secured by a mortgage on the leaseholds and equipment used in resulting wells. Simultaneously, the operator enters into a fixed price no-out turnkey contract to drill wells, at no further cost to the investors. The operator also simultaneously obtains a completion joint venture option under which the operator can recover an interest in a completed well by remitting to the limited partners a portion of the cash consideration which they paid.

On its 1972 return this taxpayer and Brountas deducted their pro rata share of expenses of the limited partnership, in excess of their respective cash investments, up to the full purchase price, including the nonrecourse notes. There is no question but that a taxpayer which has made a proper election may deduct all "intangible drilling and development costs" in the year incurred. 26

U.S.C. § 263(c) (Supp. IV 1980); Treas. Reg. § 1.612-4(a)(1965). Also, an accrual basis partnership can accrue as an expense future fixed obligations. Such deductions from income, for a partnership, flow through it to the partners. Thus the limited partners contend that they can deduct from other income losses resulting from whatever expense the limited partnership may accrue.

The Internal Revenue Code, however, limits the share of partnership losses a partner may deduct to the amount of his basis in the partnership. 26 U.S.C. §§ 705, 722 (1976). Another provision of the Code states that "[a]ny increase in a partner's share of the liabilities of a partnership . . . shall be considered as a contribution of money. . . ." 26 U.S.C. § 752(a). The taxpayer is not liable on the nonrecourse note. It contends, however, in reliance on *Crane v. Commissioner*, 331 U.S. 1 (1947), that when property is acquired subject to a nonrecourse obligation secured by a mortgage on property acquired, the mortgage is the equivalent of a personal obligation, and the obligation will be recognized as part of the taxpayer's basis. Alternatively, the taxpayer contends that in any event 26 U.S.C. § 636 authorizes the contested deduction because the nonrecourse note is a "production payment that is carved out of a mineral property."

The Tax Court rejected the taxpayer's argument that 26 U.S.C. § 752(a) authorizes the deduction, holding that *Crane v. Commissioner* does not apply to liabilities that are both nonrecourse and essentially contingent. Here, as a practical matter, the payment of the nonrecourse note is contingent upon the discovery of recoverable amounts of gas or oil. The security is otherwise of little value. The *Brountas* and *Gibson Products* courts adopted the same position.

The Tax Court concluded, however, that 26 U.S.C. § 636 authorized the deduction. The court reasoned: (1)

that the nonrecourse payments amounted to production payments; (2) that under section 636 production payments are treated as loans; and (3) that treating the payments as loans from the operator, who expected those loans to be paid, required that they be treated as liabilities increasing the taxpayer's basis. The *Brountas* and *Gibson Products* courts rejected this interpretation of section 636. The essential flaw in the Tax Court's reasoning, recognized by both courts, is that section 636 does not by its terms make any change in the rule that speculative or contingent liabilities may not be accrued and deducted.

The taxpayer's cross-appeal presents a different issue. It took a deduction for losses for abandonment of parts of individual leaseholds. While leaseholds were not in production the leasehold owners owed "delay rentals." If these payments ceased, the limited partnership presumably lost its leasehold interest. The leaseholds were, however, divided for drilling purpose into "horizons" or segments. When a test well produced a dry hole a geologist would recommend whether to abandon the segment where the dry hole was drilled or the entire leasehold. Deductions were taken for abandonment of some segments, even though the entire leasehold was not abandoned and the limited partnership continued to pay delay rentals.

The Tax Court held that so long as the investors continued to pay delay rentals they still had the right to explore all strata in the leasehold, and thus there was no "*intention* to abandon coupled with an *act* of abandonment." *Massey-Ferguson, Inc. v. Commissioner*, 59 T.C. 220, 225 (1972) (emphasis supplied). The *Brountas* court affirmed this finding.

The *Brountas* and *Gibson Products* opinions analyze at length the two reasons relied upon by the taxpayer for deductibility of the expenses of the limited partnership represented by the nonrecourse notes. *Brountas*, more-

over, discusses in detail the abandonment issue. The appeals were argued before both courts by the same attorney. Detailed treatment by us of any of these issues would serve no useful purpose. It suffices to observe that the Court of Appeals for the First Circuit properly disposed of the companion appeal arising out of the same trial record.

The decision of the Tax Court shall be affirmed as to the issue appealed by the taxpayer, but reversed as to the issue appealed by the Commissioner, and the case remanded to the Tax Court for further proceedings.

UNITED STATES COURT OF APPEALS
FOR THE THIRD CIRCUIT

Nos. 82-3009/82-3010

CRC CORPORATION,
Appellant in No. 82-3009

vs.

COMMISSIONER OF INTERNAL REVENUE,
Appellant in No. 82-3010

(T.C. No. 8497-76)

ON APPEAL FROM A DECISION OF THE UNITED STATES TAX COURT

Present: GIBBONS, WEIS and SLOVITER, *Circuit Judges*

JUDGMENT

This cause came on to be heard on the record from the United States Tax Court, and was argued by counsel on September 15, 1982.

On consideration whereof, it is now here ordered, adjudged and decreed by this Court that the decision of the said Tax Court in this cause be, and the same is hereby affirmed with respect to the issue appealed by the taxpayer and reversed with respect to the issue appealed by the Commissioner and the cause remanded to the said Tax Court for further proceedings.

ATTEST:

/s/ M. ELIZABETH FERGUSON
Chief Deputy Clerk

November 16, 1982

UNITED STATES COURT OF APPEALS
FOR THE THIRD CIRCUIT

Nos. 82-3009 and 82-3010

CRC CORPORATION,

Appellant

vs.

COMMISSIONER OF INTERNAL REVENUE

SUR PETITION FOR REHEARING

Present: SEITZ, *Chief Judge*, ALDISERT, ADAMS, GIBBONS, HUNTER, WEIS, GARTH, HIGGINBOTHAM, SLOVITER and BECKER, *Circuit Judges*

The petition for rehearing filed by appellant CRC Corporation in the above entitled case having been submitted to the judges who participated in the decision of this court and to all the other available circuit judges of the circuit in regular active service, and no judge who concurred in the decision having asked for rehearing, and a majority of the circuit judges of the circuit in regular active service not having voted for rehearing by the court in banc, the petition for rehearing is denied.

By the Court,

/s/ JOHN J. GIBBONS
Judge

Dated: Dec. 10, 1982

73 T.C. No. 42

UNITED STATES TAX COURT

PAUL P. BROUNTAS and LYNN T. BROUNTAS,
Petitioners

v.

COMMISSIONER OF INTERNAL REVENUE,
Respondent

CRC CORPORATION,
Petitioner

v.

COMMISSIONER OF INTERNAL REVENUE,
Respondent

Docket Nos. 8231-76, 8497-76
8698-77, 6255-78 [1]

Filed December 26, 1979.

Petitioner Brountas was a limited partner in an oil and gas drilling partnership, Coral I, while petitioner CRC was a general partner in Coral I, Coral II (another similar venture), and a direct investor in other drilling ventures. Each of these ventures used the following basic format, with variations. An exploratory drilling prospect would be presented to CRC by an operator. If the geology appeared favorable, CRC would purchase for itself, or cause a limited partnership such as Coral I or Coral II to purchase, the operator's leasehold interest and the operator's promise to drill to the hoped-for producing zone on a "no-out turnkey" basis. The operator would be paid in cash 40 percent of the nominal total price of the lease-

1. These cases have been consolidated for purposes of trial, briefing and opinion as to the issues decided herein.

hold and drilling contract. The purchaser would execute a nonrecourse note to the operator or a "lender" for the 60 percent balance, payable solely from production, if any, from the prospect or from certain other prospects (usually two) with respect to which the note would be cross-collateralized. The operator would also receive a completion option, permitting it to pay the costs of completing the well if potential production was discovered and repay the purchaser's lease acquisition price and thereby regain a 40 percent interest in the well. The cash portion of the price for the drilling contract would have alone been a fair price for a "Gulf Coast Clause" or "standard turnkey" drilling contract, which, unlike the no-out turnkey, relieved the operator from his responsibility if certain unfavorable conditions were found in the course of drilling. The terms of the entire package were within a reasonable range of commercial practice.

Held, on the facts, the nonrecourse notes had value and commercial reality and were not shams.

Held, further, the nonrecourse notes constituted oil or gas payments or the substantial economic equivalent within the meaning of section 636 and Regulations section 1.636-3(a)(2), and must therefore be treated for tax purposes as loans from the lender or operator to the purchasers. Therefore, the face amount of the notes was fully includible, in the case of partnership purchases, in the basis of the partners' partnership interest, as liabilities under section 752, despite the contingent nature of the obligation.

Held, further, the fact that the security for the notes was less than their face value does not prevent inclusion of the notes at face value for purposes of section 752(c). *Tufts v. Commissioner,* 70 T.C. 756 (1978), on appeal (5th Cir., Apr. 23, 1979), followed.

Held, further, the partnerships were entitled to deductions for intangible drilling and development costs equal to the face value of the no-out turnkey drilling contract.

Held, further, interest payable on the nonrecourse notes was deductible by the accrual-basis partnerships as it accrued, despite the contingent nature of the obligation, under Regulations section 1.636-1(a)(3), Example 1.

Held, further, respondent properly disallowed deductions to the partnership or CRC for the 60 percent note portion of the lease purchase price. On the facts, these were not advanced royalties, for the leasehold interests were acquired from the operators by purchase and not by lease.

Held, further, respondent properly disallowed deductions claimed by the partnerships for management fees to the extent these fees in fact represented sales commission expenses paid by CRC and reimbursed by the partnerships to CRC.

Held, further, respondent properly disallowed abandonment losses of capitalized leasehold acquisition expenses of unproductive leases for periods prior to acts of definitive abandonment (i.e., periods before delay rentals were permitted to fall due unpaid). *A.T. Jergins Trust v. Commissioner,* 22 B.T.A. 551 (1931), affd. on other issues, 288 U.S. 508 (1933), revg. 61 F. 2d 92 (9th Cir. 1932), followed.

Held, further, fraud penalties against CRC are not sustained.

Reserved for further briefing and opinion is the issue of the timing and character of cancellation of indebtedness income generated in the case of nonrecourse indebtedness secured only by non-productive leaseholds.

Thomas B. Rutter, for the petitioners.

Bernard Nelson, M. Kevin Phalin, David Johnson and *Bob Hollohan,* for the respondent.

HALL, *Judge:* Respondent determined deficiencies, plus additions to the tax for fraud under section 6653(b)[2] and accumulated earnings tax under section 531, as follows:

Petitioner	*Year*	*Docket No.*	*Deficiency*	*§ 531*	*§ 6653(b)*
Paul & Lynn Brountas	1972	8231-76	$ 6,283.35	$ none	$ none
Paul & Lynn Brountas	1973	6255-78	19,006.43	none	none
CRC Corporation	1972	8497-76	238,826.00	152,485.00	195,656.00
CRC Corporation	1973	8698-77	272,821.00	none	136,411.00

Petitioner Paul Brountas was a limited partner in a "leveraged" oil and gas drilling venture ("Coral I"), and petitioner CRC Corporation ("CRC") was both the general partner and a limited partner in Coral I and in another "leveraged" oil and gas drilling venture ("Coral II"). CRC also made direct investments for its own account in similar ventures. These ventures were "leveraged" in that they used nonrecourse notes as a portion of the consideration (in addition to cash contributed by CRC and various limited partners) in transactions with unrelated oil and gas operators. Coral I, Coral II and CRC claimed deductions in 1972 and 1973 in excess of the amount of cash they expended in exploratory oil and gas drilling, giving rise to losses in both years, and petitioners Brountas and CRC reported their distributive shares of Coral I's and Coral II's claimed losses in 1972 and 1973. Other issues having been severed for trial at a later date,[3] the issues for decision at this time are:

2. All statutory references are to the Internal Revenue Code of 1954, as in effect during the years in issue.

3. The following adjustments in the notices of deficiency have been severed for trial at a later date:

1. Whether Coral I, Coral II and CRC are entitled to deductions for intangible drilling and development costs in excess of the amount of cash spent in these transactions. Specifically, we must consider:

(a) Whether the nonrecourse notes were shams.

(b) If the nonrecourse notes were not shams, whether petitioners may include the face amount of these notes in their bases in their partnership interests. This issue involves consideration of (i) the applicability of section 636 (production payments) to these notes, and (ii) whether petitioners' bases are limited to the fair market value of the security for the nonrecourse notes.

(c) If these nonrecourse notes provide basis, the amount of the intangible development and drilling costs which Coral I, Coral II and CRC are entitled to deduct.

2. Whether Coral I, Coral II and CRC are entitled to interest deductions relating to interest paid on the nonrecourse notes.

3. Whether Coral I, Coral II and CRC are entitled to claimed deductions for advanced royalties.

4. Whether Coral I and Coral II are entitled to claimed deductions for management fees.

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3. (Cont'd.)

Petitioner	*Docket No.*	*Adjustments severed*
Paul & Lynn Brountas	8231-76	No adjustments severed
Paul & Lynn Brountas	6255-78	Adjustment (a) (re Special 342-1973 Drilling Venture I)
CRC Corporation	8497-76	Accumulated earnings tax
CRC Corporation	8698-77	Adjustments (d), (e), (f), (g), (i), and section 6653(b) addition to tax

5. Whether Coral I, Coral II and CRC are entitled to claimed deductions for abandonment losses.

6. With respect to 1973, whether petitioners realized ordinary income from discharge of the indebtedness on these notes.[4]

7. Whether any part of petitioner CRC's underpayment of tax for 1972 was due to fraud.

Findings of Fact

Some of the facts have been stipulated by the parties and are found accordingly.

At the time they filed their petitions, Paul and Lynn Brountas were residents of Weston, Massachusetts. Lynn Brountas is a party solely by virtue of the fact that she filed joint returns with her husband Paul Brountas (hereinafter Brountas) for the years in issue.

Petitioner CRC Corporation ("CRC") is a Delaware corporation. At the time it filed its petitions, CRC's principal office was located in Jenkintown, Pennsylvania.

Brountas was a limited partner in Special Coral 1972 Drilling Venture I ("Coral I") during the years in issue. During these years, CRC was both the general partner and a limited partner in Coral I and in Special Coral 1972 Drilling Venture II ("Coral II"). Coral I and Coral II are duly organized limited partnerships under the laws of the State of Texas. At all times pertinent hereto, Coral I, Coral II and CRC used the accrual method of accounting.

Brountas is a lawyer. In 1972 he contributed $10,000 in cash to Coral I; in 1973 he contributed an additional $1,000 cash for an additional development program for

4. By order dated December 26, 1979, we have requested supplemental briefs from the parties with respect to this issue, which will be addressed in a supplemental opinion.

Coral I. He had a 0.8811 percent capital and profits interest in Coral I during both years. CRC contributed $25,000 cash to Coral I in 1972, $25,000 cash to Coral II in 1972, and an additional $2,500 to each partnership in 1973 for additional development. CRC had a 2.2026 percent interest in Coral I during 1972 and 1973 and a 2.1872 percent interest in Coral II during those years. CRC made direct cash investments in various partnerships which engaged in leveraged drilling operations. Such investments totaled $359,000 in 1972.

A. Background

The format for the leveraged oil and gas drilling ventures at issue in this case was developed by Milton Dauber and William Soter. Brief background information concerning these two individuals, their formation of CRC, and the oil and gas industry in general will assist in understanding this case.

Dauber is a tax attorney. In 1969 he left the private practice of law and, together with Charles Scoggins, organized a limited partnership, GeoDynamics Investors, Ltd., for the purpose of raising money for the purchase of oil and gas leasehold interests for resale. Scoggins had previously been employed as a geologist, a Texas state legislator and an independent consultant. GeoDynamics Investors, Ltd. consisted of two general partners, Scoggins and Dauber, as well as 18 to 20 limited partners. Its offices were in Corpus Christi, Texas, and Jenkintown, Pennsylvania. Scoggins headed the office in Corpus Christi, and he was responsible for the selection of attractive oil and gas leasehold interests for purchase by the partnership. Dauber headed the office in Jenkintown, and he was responsible for the legal, accounting, financial and administrative operations of the partnership.

Several months after the formation of GeoDynamics Investors, Ltd., Scoggins and Dauber organized Geo-

Dynamics Oil and Gas, Inc. ("GeoDynamics") which acquired the assets of GeoDynamics Investors, Ltd. in exchange for its stock. Concurrently, the partnership, GeoDynamics Investors, Ltd. was dissolved. After this exchange, Scoggins and Dauber each owned 25 percent of the common stock of GeoDynamics, and the remaining 50 percent was divided among the former limited partners. Scoggins became the president of GeoDynamics, and Dauber became the chairman of its board of directors.

Like its predecessor, GeoDynamics engaged in the acquisition of leasehold interests in oil and gas properties for resale. GeoDynamics also engaged in the oil and gas business as an "operator." An operator is an entrepreneur who attempts to locate and obtain oil and gas prospects. Initially an operator's geological staff searches for geographical areas beneath the surface of which may exist oil and gas reserves in commercial quantities. These areas are called "prospects." The operator then attempts to obtain leasehold rights to these mineral interests by negotiating with either the landowner or other owners of the mineral rights. Once the operator has obtained the mineral leasehold rights, and has decided to drill on the prospect, the operator usually attempts to bring in venture capital partners for the drilling. An operator, if it does not have sufficient funds of its own, will attempt to have the cost of drilling a test well on the prospect paid for by others.[5] Of course, by the time the prospect has been located and the leasehold rights have been acquired, the operator has invested its own capital and expertise in the location and acquisition of the mineral properties to be explored.

5. An operator would prefer to use its own money to drill prospects, since it would then have a larger interest in the property if successful. As a practical matter, however, most operators do not have the financial resources to fund their own exploratory drilling.

Once financing has been obtained, the next step is the drilling of the prospect. The drilling is usually performed by a drilling contractor. The drilling contractor's business is distinct from that of an operator; the drilling contractor simply brings his drilling rig to the prospect, drills the hole, and then takes his rig to a different location. In most cases the drilling contractor does not care whether or not oil is discovered—his job is simply to drill the hole. In contrast, the operator's business is to profit by creating for itself an equity in the oil and gas discovered.[6]

There is no "standard" financing arrangement by which an operator and outside investors develop a prospect; numerous forms of trades are used in the oil field. Among the types of interests which can be created, in varying proportions, are royalties, overriding royalties, net profits interests, production payments, carried interests and working interests.[7] In other words, there is no set pattern to deals between operators and outside investors.

On the other hand, there is a relatively "standard" arrangement among partners within the industry called a "third for a quarter" deal. The operator transfers three-quarters of the leasehold interest in a prospect to another person (or persons) in return for payment of 100 percent of the cost of drilling and, if successful, completing the test well on the prospect. For example, if the deal included three people plus the operator, each person (other than the operator) would put up one-third of the drilling cost and would receive a one-quarter interest in the well. The operator's quarter interest in the well is its reward for

6. For this reason, operators are loath to sell their entire interest in a prospect they have created; in contrast, lease brokers obtain leases, sell them, and profit thereby.

7. For an explanation of these different interests, see F. Burke & R. Bowhay, Income Taxation of Natural Resources par. 2.01-2.08 (1979).

searching for, identifying and leasing the prospect as well as the efforts it exerts in supervising the actual drilling and completion.

In 1969 GeoDynamics entered into arrangements as an operator with two outside investment groups, First Cameron Corporation and Intramerican Drilling Fund 1969 ("Intramerican Fund"). Intramerican Fund was a Pennsylvania partnership organized for the purpose of investing in oil and gas exploration. In its operations with Intramerican Fund, GeoDynamics provided the people who ran Intramerican Management Corporation ("Intramerican Management"), which acted as a general partner for Intramerican Fund. GeoDynamics owned 49 per cent of the stock of Intramerican Management, and Dauber and Scoggins were president and vice-president, respectively, of Intramerican Management. Scoggins was the general exploration manager, and he supervised the expenditure of the investors' funds through the acquisition of leasehold interests in prospects and the negotiation of drilling contracts for test wells on these prospects.

The drilling contracts which Scoggins negotiated for Intramerican Fund were "standard turnkey contracts." In a "standard turnkey," the operator agrees to drill a well to a certain depth for a certain amount of money. However, in the standard turnkey the operator is given what is commonly called a "Gulf Coast Clause," which allows the operator "outs" to cease drilling if certain specified unfavorable conditions are reached. Among the conditions usually specified in a Gulf Coast Clause are high or low pressure, impenetrable subsurface formations, loss of mud circulation [8] and salt.

8. Loss of mud circulation refers to the drilling mud which is pumped down the drilling pipe, through the bit, and returns along the walls of the shaft of the drilled hole. The mud simultaneously cools the drilling bit, removes drilling cuttings and seals the walls of the shaft.

For example, if a high pressure subsurface area is encountered, a "blow out" can result. If a blow out occurs the well can easily catch on fire; in any case, considerable amounts must be spent to bring the well under control. Off-shore the costs and dangers are multiplied. (The record does not disclose whether any of the prospects in issue were offshore.) On the other hand, if a low pressure subsurface area is encountered, the well can "fall in." When a well falls in, the drilling mud and the drilling pipe are usually lost into the hole. Given the high cost of both drilling mud and drilling pipe, low pressure also may be very costly.

The Intramerican Fund raised approximately $1 million from investor subscriptions, with which it drilled, through GeoDynamics, 34 test wells. A similar program, Intramerican Drilling Fund 1970 ("Intramerican 1970"), was formed, and GeoDynamics again was the operating partner. Intramerican 1970 raised approximately $1.2 million with which it drilled 38 wells.

Although GeoDynamics continued as an operator for Intramerican in 1970, basically its business changed in that year. GeoDynamics' board of directors decided that neither the lease acquisition nor operating activities were as profitable as planned. Accordingly, it was decided to turn GeoDynamics into a money management fund. In the oil and gas business, a money management fund is an organization which raises money and places it with various operators for the purpose of conducting exploration. However, in contrast to GeoDynamics' earlier role, a money management fund does not actively function as an operator.

At the time GeoDynamics was changing its business, Soter along with Kenneth Avanzino and Martin Fribush formed a new, unrelated corporation, Comprehensive Re-

sources Corporation ("Comprehensive"). Soter was also a tax attorney who had left private practice to enter the oil and gas business; he met Dauber in early 1970. Soter developed a format in which limited partnerships were used to obtain outside investors in oil and gas exploration and development.[9] The limited partnership format was advantageous since it allowed the outside investors to limit their liability to the amount of their contribution to the partnership. Moreover, Comprehensive would serve as the general partner of these limited partnerships, in contrast to the previous norm in the oil and gas industry in which the operator served as the general partner. Soter felt that Comprehensive could better serve the investors' interests.[10]

Soter and Dauber incorporated in the partnerships two other important changes in the format of oil and gas exploration programs.[11] The first was the "no-out turnkey drilling contract" under which the operator never had a right to quit drilling before reaching the agreed depth—there were no escape clauses. The Gulf Coast Clause provision which had existed in most prior contracts was

9. Prior to this time, most oil and gas exploration was conducted through joint ventures, although some groups (such as Intramerican) had begun to use the limited partnership format.

10. In pre-1970 transactions using limited partnerships, the operator usually served as the general partner. The operator would both raise money from outside investors and drill the well. If drilling difficulties were encountered, the operator would request additional funds from the limited partners. If no additional funds were forthcoming, the investors could be left with an uncompleted well. There existed a potential for a conflict of interest for the operator, since he represented both himself (in drilling) and the investors (who were paying).

11. These changes were devised jointly since Comprehensive and GeoDynamics were functioning as co-general partners at this time.

eliminated. From the investor's (limited partner's) point of view this was important since the investor was guaranteed (to the extent of the operator's assets) that all wells which were contracted for would be drilled regardless of difficulties encountered and, moreover, that the investor would not have to contribute additional drilling funds. All the financial risks of drilling were placed on the operator. But the investor pays extra for the protection which the no-out turnkey drilling contract affords him, and the operator receives the extra money because of its added risks.

The possible adverse effects of the no-out turnkey drilling obligation on an operator was illustrated by the Boyken Church Prospect which Patrick Petroleum Company drilled for CRC. Patrick Petroleum had estimated the cost of this well to be $375,000, but its actual out-of-pocket cost was $975,000 because the well had to be drilled three times. The first time the well was drilled, there was a blow out when a high pressure reservoir was encountered. The second time the well was drilled, the drilling pipe separated and a portion was lost. On the third attempt, the well was successfully drilled, but it was a dry hole.

The second major change was that "leverage" was added to the transactions with the operators. A portion of the sum agreed to be paid to the operator for the no-out turnkey drilling contract was represented by a nonrecourse note. The importance of leverage in these transactions was, first, that the investors would have only the contributed cash at risk. Second, Soter believed that the amount of the nonrecourse notes would be included in the investors' bases in their limited partnership interests, allowing the promoters to hold out the expectation to potential limited partners of deductions beyond the cash contributed.

In 1970 Comprehensive and GeoDynamics formed limited partnerships employing this format. A limited partnership (with Comprehensive and GeoDynamics as co-general partners, and the investors as limited partners) would purchase leases for an agreed "lease purchase price" from the operators. The limited partnership and the operator would then enter into a no-out turnkey drilling contract at an agreed "drilling contract price." The contract obligated the operator to furnish to the limited partnership a "log" taken at "casing point." Casing point is the depth at which the well is evaluated; it is the point at which the operator believes, on the basis of geological evaluation, that hydrocarbons may be found. In other words, casing point is the depth to which the operator has obligated itself to drill. When casing point is reached, the well is tested for the presence of hydrocarbons, usually by an electronic (sic) induction log. This log furnishes information on the basis of which a decision is made whether to complete the well. If the logs do not justify completion, the well is a "dry hole" which is then plugged and abandoned.

If the total contract price (lease purchase and drilling contract prices together) were $100,000, the limited partnership would pay the operator $29,000 in cash. In form the limited partnership would "borrow" $71,000 from the operator in return for a nonrecourse note secured by 80 percent of the partnership's leasehold interests. The limited partnership would then reconvey the amount "borrowed" ($71,000) to the operator in payment of the unpaid part of the total "contract price" ($100,000). In substance, the operator received $29,000 in cash plus a note for $71,000 which was payable solely out of production.[12] The note was cross-collateralized, that is, was pay-

12. The partnerships would also "borrow" 71 percent of the lease purchase price. The note also covered this amount, so the

able out of any production from several prospects, rather than one.

In addition, as part of the package of rights transferred to the operator in 1970 as consideration for the drilling contract and the leases, the operator received a completion option and a conversion right. The completion option entitled the operator, after casing point had been reached, to complete the well and pay all costs related thereto.[13] In return, the operator received an interest in the mineral property equal to the ratio of completion costs to total drilling costs (completion plus drilling to casing point) actually incurred.[14] For example, if total

12. (Cont'd.)

operator received for the leases which it conveyed to the partnership 29 percent of the lease purchase price in cash and the remaining 71 percent of the lease purchase price via the note.

13. Completion costs are costs incurred after an apparently productive well has been drilled and logged. They include, *inter alia*, the cost of production pipe (called casing pipe, which is different from drilling or protective pipe) and surface facilities necessary to place a well under production. The cost of completion after casing point is often as much as 40 per cent of the total cost (through completion) of a test well. In other words, if the cost of drilling to casing point and testing a well were $60,000, completion might cost an additional $40,000. When a decision to attempt completion is made on the basis of information obtained from the electronic logs, there is no guarantee that a commercially productive well will result. For example, fresh water produces test results identical to oil and gas, so a well can be completed and produce only fresh water. Additionally, even if oil or gas is present, the pressure or the quantity of minerals may be insufficient to justify production. In short, the completion option gave the operators a chance to earn an interest in the well, but there were considerable risks of loss attached.

14. Specifically, if the operator elected to complete, a "completion joint venture" would be formed and the operator's and the partnership's respective interests in the well would be determined by their partnership interest, which was established by this formula.

drilling costs were $100,000, of which pre-casing point costs were $60,000 and completion costs were $40,000, the operator would receive a 40 percent interest in the well. However, after the operator recovered its completion costs from production ("pay out"), one-quarter of the operator's interest so earned would revert to the investors under a so-called "back-in." In the above example, one-quarter of the operator's 40 percent interest—10 percent of total production—would revert to the investors.

The operator also received a "conversion right" to convert its nonrecourse note into 25 percent of the investors' interest, calculated after the operator exercised the completion option but before the back-in. Using the above example, under the completion option the operator's and investors' interests were, respectively, 40 percent and 60 percent of production. If the operator exercised the conversion right, 25 percent of the investors' 60 percent interest, or 15 percent of production, would be transferred from the investors to the operator. Accordingly, the operator's and investors' interests would become, respectively, 55 percent and 45 percent. However, the back-in was made without reference to the conversion right, so that at pay out one-quarter of the interest which the operator received under the completion option, or 10 percent of production, would revert from the operator to the investors. In this example, the interests of the operator and the investors would thus become after pay out 45 and 55 percent respectively.

In sum, the operator received four property rights when it entered into a drilling contract in 1970 with a limited partnership—cash, a nonrecourse note, the conversion right and a completion option. As consideration, the operator undertook a no-out turnkey drilling contract, with its attendant risks.

In 1970 Scoggins or Dauber negotiated with various operators concerning GeoDynamics' leveraged drilling program; the contracts Scoggins negotiated were subject to Dauber's approval. Only operators with net operating loss carryovers were willing to enter into this type of leveraged drilling program. Other operators would not do so because the face amount of the note was believed to constitute income when received for tax purposes without yielding any cash with which to pay the tax thereon.

Within GeoDynamic's format, Scoggins negotiated prices with various operators. McMoRan Exploration Co. of New Orleans, Louisiana ("McMoRan") was a major one. Scoggins and McMoRan, for example, followed a basic pattern in which McMoRan's estimated turnkey price was increased 20 per cent over a "Gulf Coast" contract price for risks in "less risky" areas and more for risks in "risky or high pressure areas." The amount negotiated with the operators would be the total turnkey contract cost. Of this total turnkey price (*e.g.*, $100,000) 29 percent was paid in cash, and the remainder was represented by the note. The operators hoped to cover all of their out-of-pocket expenses with the cash.

Sales under the 1970 program were very successful. GeoDynamics and Comprehensive raised over $8 million from investors which was placed, through limited partnerships, in oil and gas exploration projects with various operators. The drilling itself was also successful, most notably McMoRan's Ransom Island project. Due to the leverage feature of the arrangement (*i.e.*, the nonrecourse note of $71,000), an investor (a limited partner) reported income tax deductions in 1970 of almost three times the amount he put up in cash, plus obtaining an interest in producing wells.

Several changes were made in late 1970 and 1971. First, Dauber discharged Scoggins for alleged incom-

petence and dishonesty, and gave Scoggins' position to Bill Floyd, who had worked as an exploration manager for Gulf Oil Company before he joined GeoDynamics in 1969. Second, in late 1970 a new corporation, GeoResources Management Corporation ("GeoResources") was formed. The stock of GeoResources was owned equally by GeoDynamics and Comprehensive. GeoResources was formed to function as the general partner in future publicly-offered leveraged drilling funds.[15] Third, in July 1971 CRC was organized to effect a business combination. CRC acquired all of the outstanding stock of Comprehensive and GeoDynamics, each of which owned 50 per cent of the stock of GeoResources. Dauber became chairman of the board of directors of CRC, and Soter became president. For purposes of these findings and this opinion, CRC and its subsidiaries—GeoDynamics, GeoResources and Comprehensive—will henceforth be referred to collectively as CRC, irrespective of which corporate entity actually became the general partner in any given drilling fund.

In addition to these changes, the contract format was changed in three major ways.[16] First, the conversion right with respect to the note was eliminated. Second, the completion right was changed so that the interest in the well earned by the completing operator was no longer

15. In 1970 the limited partnerships were not "publicly offered" and were not registered with the Securities and Exchange Commission. In contrast, beginning in 1971 GeoResources functioned as the general partner for drilling funds for which prospectuses were registered with the SEC.

16. Since the 1972 contract format, which was very similar to the 1971 format, is explained in detail *infra*, we set forth only a rough description of the changes at this point. Minor changes are not detailed here. A more detailed examination of the 1970 and 1971 programs is not necessary since they merely provide background for the 1972 program which is in issue in this case.

determined by the ratio of completion expenses to total expenses, but became a fixed percentage—usually 40 percent.[17] Third, the amount of cash contributed by the limited partnerships was increased. In contrast to the 29 percent cash in the 1970 program, in 1971 the partnership paid in cash 40 percent of the total no-out turnkey contract price, with the remainder of the price represented by the nonrecourse note.[18] This increased cash was apparently intended to compensate the operator for the lack of the conversion right.

The 1971 program also enjoyed successful sales. Approximately $30 million was raised from investors, with $10 million being placed with operators for exploration programs through a limited partnership registered with the SEC and the remainder through unregistered limited partnerships.

B. The 1972 Drilling Program

1. In General. In 1972 CRC organized and managed a leveraged program similar to the 1971 program. Investment capital totaling approximately $25 million was placed through two registered limited partnerships, GeoResources Drilling Fund 1972 Annual Program and GeoResources Drilling Fund 1972 Year End Program. Additional investment capital totaling approximately $10 million was raised and placed in 1972 through twenty unregistered limited partnerships, including Coral I and

17. This change simplified the determination of each party's interest upon completion, since an exact accounting of the amounts expended was not necessary. It also guaranteed that the operator could not, due to the completion option, earn a larger interest in the well than the partnership had.

18. Apparently 40 percent of the lease purchase price was also paid in cash, with the remainder of the lease price represented by the nonrecourse note.

Coral II. CRC served as the general partner for Coral I and Coral II.

In 1972 CRC, either on its own behalf or on behalf of the limited partnerships (such as Coral I and Coral II), entered into various agreements with various operators. These agreements, which generally consisted of (1) a Lease Purchase and Turnkey Drilling Agreement, (2) Loan Agreement, (3) Promissory Note ("Note"), (4) Mortgage, Deed of Trust, Assignment of Security Interest ("Mortgage"), and (5) Joint Venture Agreement, would pertain to a "package" of prospects submitted by an operator. A package usually involved two or more (typically three) noncontiguous oil and gas prospects to be drilled by a single operator. Participation in the various packages was generally shared by various limited partnerships. A limited partnership invested in many packages, receiving a percentage interest in each, in order to obtain diversification. As a general rule, no more than 10 percent of a limited partnership's funds were invested in any given package. Shown below are the 24 packages participated in by Coral I and Coral II in 1972:

Package Number	*Name of Operator*	*Coral I Partnership Participation*	*Coral II Partnership Participation*
72-1	McMoRan (Elpac)	.3395	.34405
2	Powers (Poco)	.11632	.11788
3	Western States	.38517	.39033
4	McMoRan (Elpac)	.38517	.39033
5	McMoRan (Elpac)	.38517	.39033
6	McMoRan (Elpac)	.38517	.39033
7	McMoRan (Elpac)	.0516	.0520
8	Gibraltar (Elpac)	.0516	.0520
9	Dynamic	.0516	.0520
10	Emerald	.0779	.0785
11	Gibraltar (Elpac)	.0779	.0785
12	McMoRan (Elpac)	.0779	.0785

Package Number	*Name of Operator*	*Coral I Partnership Participation*	*Coral II Partnership Participation*
13	Sinclair (Elpac)	.0779	.0785
14	Powers (Poco)	.0779	.0785
15	Gibraltar (Elpac)	.0779	.0785
16	McMoRan (Elpac)	.0779	.0785
17	McMoRan (Elpac)	.0779	.0785
18	McMoRan (Elpac)	.0779	.0785
20	Emerald	.03	.0280
22	Birthright	.03	.0280
42	Gibraltar (Elpac)	.013	.013
31	McMoRan (Elpac)	.0097	.0088
32	Patrick	.0188	.0172
96	Arriba	.0169	.0172

At times CRC or its subsidiaries would participate in a package in an individual capacity. CRC entered into the following 28 packages during 1972 as an individual investor for its own account:

Package Number	*Name of Operator*	*CRC Participation*
72-35	Emerald	.0394
37	Duquesne	.0394
43	Gibraltar (Elpac)	.0401
44	Cane	.0394
45	Cane	.0394
51	Patrick	.0394
52	Patrick	.0042
61	Nor-Am	.0394
63	Triton	.0394
67	Gibraltar (Elpac)	.0401
68	Nor-Am	.0394
69	Sinclair (Elpac)	.0401
70	Corpening	.0394
72	McMoRan (Elpac)	.0401
75	Nor-Am	.0394
76	Scoggins	.0394
77	McMoRan (Elpac)	.0042
78	McMoRan (Elpac)	.0401
79	McMoRan (Elpac)	.0401
80	McMoRan (Elpac)	.0401

Package Number	*Name of Operator*	*CRC Participation*
81	McMoRan (Elpac)	.0401
82	McMoRan (Elpac)	.0401
83	McMoRan (Elpac)	.0401
84	McMoRan (Elpac)	.0401
85	McMoRan (Elpac)	.0401
86	Tech-Sym	.0394
87	McMoRan	.0401
88	Gibraltar (Elpac)	.0401

2. The "Standard" Package. The transactions which CRC and the limited partnerships entered into, as well as the documentation thereof, were standardized to a significant degree.[19] The agreements were entered into by the operators and, on behalf of the limited partnerships and CRC (hereinafter collectively referred to as "Investors"), by CRC. Typically, the five agreements mentioned above with respect to a package were executed simultaneously.

The Lease Purchase and Turnkey Drilling Agreement provided, first, for the transfer from the operator to the Investors of the operator's interest in the oil, gas and/or mineral leases with respect to the prospects (usually three) in the package. A price ("lease purchase price") is stated for each lease in the package. Second, the operator agreed to drill a test well on each prospect at a specified location to a specified depth. The operator's obligation to drill the well was a no-out turnkey obligation, meaning that the operator agreed to drill, or cause to be drilled, a well to the agreed depth and to perform all tests and logs which a prudent operator would reasonably perform for its own account. The operator was obligated to furnish all equipment, drilling rigs, drilling mud, location preparation, etc. necessary for the drilling of the well. This obligation was absolute, regardless of circumstances or difficulties, foreseen or unforeseen, which might be

19. A major exception—the transactions involving Elpac—is discussed *infra*.

encountered. If any well were a dry hole, the operator was obligated to plug and abandon the hole and restore the surface. In consideration for this no-out turnkey drilling agreement, which applied to all the prospects in a package, the Investors promised to pay the operator a single amount ("drilling contract price"). The agreement further provided that the covenants of payment by the Investors and the promise of performance by the operator were mutually independent.

The Loan Agreement, Note and Mortgage were all executed at the time the Lease Purchase and Turnkey Drilling Agreement was executed. Each Loan Agreement provided that the operator/lender would lend to the partnership an agreed-upon sum to be used by the partnership in payment of a portion of both the lease purchase price and of the drilling contract price under the related Lease Purchase and Turnkey Drilling Agreement. The agreed-upon sum was usually 60 percent of the combined lease acquisition cost and turnkey drilling cost, although the percentage varied in some packages. For example, if the total cost of the lease purchase and the drilling contract were $100,000, the loan (hereinafter the "note portion") would be $60,000; the remaining $40,000 would be the Investors' contribution (the "cash portion"). The Loan Agreement provided that any sum lent to the partnership by the operator bore interest at the rate of 6½ percent per annum from the date of the loan and was payable upon demand on or after December 31, 1978. The loan was not subordinated to any other debts.

The debt arising out of the Loan Agreement was evidenced by the Note and secured by the Mortgage. The collateral for the debt was set forth in the Loan Agreement. In a typical Loan Agreement, the collateral for the debt was as follows:

All of the indebtedness evidenced by such note or notes shall be secured by a Mortgage, Deed of Trust, Assignment and Security Agreement (the "Mortgage") substantially in the form attached as Exhibit "B" hereto, covering:

(i) 75% of all of the rights, titles, properties and interests acquired by Borrower, its successors and assigns, under the agreement; and,

(ii) 75% of all personal property and equipment in, on, used in connection with, or attributable to such rights, titles, properties and interests; and,

(iii) 53⅓% of 75% of the production from and attributable to all of borrowers rights, titles, properties and interests * * *, and the proceeds thereof; * * *

* * *

subject, however, to the terms and provisions of any instruments or agreements referred to or described in the Agreement which affect such rights, titles, properties and interests; such pledge of collateral to the lien of the Mortgage and assignment of production runs to be in form and manner as that contained in said Exhibit "B" hereto, but specifically subject to the provisions of Part V hereof.

Said assignment of production runs and proceeds realized therefrom, represented by (iii) * * * of the foregoing paragraph and Section 3.01 of the Mortgage, shall be applied on a monthly basis, towards the repayment of the indebtedness represented by the above described note or notes; such assignment of production runs and proceeds therefrom shall continue until such indebtedness is fully paid, or until

> the maturity date of such note or notes if such indebtedness is not fully paid by such date, in which latter event the remaining balance of such unpaid indebtedness shall be due and payable by Borrower to Lender, in accordance with the terms of said note or notes.

The collateral from production specified in (iii) above equaled a net interest of 40 per cent of the production from a prospect. The percentage of production specified in (iii) above varied from package to package and, within any given package, from prospect to prospect.[20] The Loan Agreement expressly provided that the borrower (partnership) had no personal liability for any loan or advance made pursuant thereto and that there was no recourse against the borrower (or any partner of the borrower, whether general or limited) for any of the indebtedness created under the Loan Agreement. The only recourse that the operator/lender had on the note was the collateral set forth above. The entire principal amount of the loan and accrued interest was payable out of oil and gas produced from (or out of the sale of) any and all leaseholds or other rights and property interests subject to the mortgage; they were not selectively payable out of the oil and gas produced from (or proceeds from the sale of) each leasehold in proportion to the loan proceeds used in the acquisition or drilling thereof. Thus, the loan was cross-collateralized in that the production from any well in the package could be used to pay off the loan.

The Loan Agreement also provided the operator/lender an option to enter into a completion joint venture with the borrower within twenty-four hours after a well

20. For example, in one package the collateral was 53⅓% of 75% of production (or 40%) for two wells, while the collateral for the third well was 66⅔% of 75% of production (or 50%).

on a prospect had been logged and tested. The completion option also provided that as to any subsequent wells drilled on a prospect the operator/lender had a right to exercise an option to enter into a separate joint venture for each subsequent development well on a prospect. The Joint Venture Agreement governed the completion joint venture to be formed if the operator/lender exercised its option. Such an operator will be sometimes referred to hereafter as a "completing operator."

Under the Joint Venture Agreement a completing operator had to pay all costs of completion, production casing, and any costs if the well were to be plugged and abandoned.[21] It also had to indemnify and hold harmless the Investors from any and all costs, expenses and liabilities incurred in connection with the completion attempt. Additionally, the completing operator had to repay the partnership the consideration the partnership had paid for the leases.[22] Finally, it was to reimburse the Investors for all tangible equipment installed in the well before the operator exercised its option to complete.

In return, the completing operator received through the Joint Venture Agreement a 40 percent interest in all income realized after completion. After completion, all costs were to be borne by the parties to the joint venture in the same ratio (*i.e.*, 40 percent by the operator, 60 percent by the Investors). If the completion attempt failed

21. The joint venture for subsequent development wells, if required, was based on different terms discussed *infra*.

22. This amount would be the lease purchase price for the prospect, as set forth in the Lease Purchase and Turnkey Drilling Agreement, less the portion of the loan which was allocable to the lease. The operators repaid the Investors the amount of cash contributed by the investors towards the purchase of the lease. The operators also cancelled the portion of the debt which related to the lease purchase price.

to produce a commercial well, the completing operator would be entitled to all equipment on the property. Additionally, when the operator exercised its completion option, the Mortgage provided for a substitution of collateral. The collateral for the Note became the Investors' interest under the Joint Venture Agreement. For example, in the Loan Agreement example above, the collateral for the loan was 53⅓ percent of 75 percent of the Investors' interest, or 40 percent of production. If the Investors received the Joint Venture Agreement a 60 percent interest in the completion joint venture, then the collateral for the Note would be 40 percent of the Investors' 60 percent interest, or 24 percent of the production from the well. Since the amount of production which was collateral for the loan varied from package to package, the amount of collateral substituted under the Mortgage varied accordingly.

All of the above terms and conditions were contained in the basic documentation executed for each package. Additional terms regarding the parties' rights after "pay out," which is the point at which the operator has recovered from his share of production all of his costs incurred in completing a well, were contained in further, concurrently executed agreements. Prior to pay out the partnership and the operator usually divided revenues according to a 60/40 ratio;[22a] the general partner (CRC or its subsidiary) was not entitled to any share of the partnership's share of production. After pay out, several changes occurred. First, in both the registered and unregistered limited partnerships the general partner became entitled to ¼ of a partnership's share, of 15 percent of production.

22a. Of course, the limited partners' share was subject to payment of the nonrecourse note. As a result of the collateral substitution described above, the repayment would usually require 24 percent of revenues.

Second, in the registered limited partnerships, the general partner also became entitled to ⅓ of the operator's interest under the Joint Venture Agreement, or 13⅓ percent of production.[23] The unregistered limited partnerships sometimes took a share of the operator's interest in production; in Coral I, this share varied from none of some operators' interest up to ⅓ of the interest of other operators. The share of one of the largest operators, McMoRan, was subject to a ⅓ back-in. The operator's share thus taken by the limited partners would be subject to the general partner's ¼ share.

The following charts illustrate the shares taken by the various parties in this contractual framework, both before and after pay out and before and after repayment of the Notes, in the case of the initial test well of (1) a registered limited partnership, (2) an unregistered limited partnership in which the limited partners were not entitled to a portion of the operator's interest after pay out, (3) an unregistered limited partnership in a McMoRan package, and (4) an unregistered limited partnership in which the limited partners were entitled to ⅓ of the operator's interest after pay out:

23. This shift after pay out is called a "back-in."

	Recipient		Relative percentages of revenue before pay out		Relative percentages of revenue after pay out	
			Before payment of nonrecourse Notes	After payment of nonrecourse Notes	Before payment of nonrecourse Notes	After payment of nonrecourse Notes
(1)	a registered limited partnership	limited partners	36%	60%	27%	45%
		general partners	0%	0%	22⅓%	28⅓%
		operator	40%	40%	26⅔%	26⅔%
		operator/lender [24]	24%	0%	24%	0%
(2)	unregistered limited partnership with no back-in	limited partners	36%	60%	27%	45%
		general partners	0%	0%	9%	15%
		operator	40%	40%	40%	40%
		operator/lender	24%	0%	24%	0%
(3)	unregistered limited partnership with 1/9 back-in (i.e., McMoRan)	limited partners	31%	55% [25]	27%	45%
		general partners	0%	0%	9%	15%
		operator	45%	45%	40%	40%
		operator/lender	24%	0%	24%	0%
(4)	unregistered limited partnership with ⅓ back-in	limited partners	36%	60%	36⅔%	55%
		general partners	0%	0%	12⅔%	18⅓%
		operator	40%	40%	26⅔%	26⅔%
		operator/lender	24%	0%	24%	0%

24. The interests of the operator and the operator/lender are shown separately due to the Elpac transaction discussed *infra*.

25. The investor/operator ratio for McMoRan was 55/45 rather than the standard 60/40 ratio.

The above discussion of costs and percentages of production in the joint venture refers only to the initial test well on each prospect. If the initial test well were successful and if additional development wells were required, both the expenses of and production from such development wells were usually shared in a 70/30 ratio; the Investors received 70 percent of the production for payment of 70 percent of the costs, while the operators contributed 30 percent of costs for 30 percent of production. Of course, all the income from the development wells was subject to the lien of the nonrecourse Notes, so the Investors' shares would be reduced accordingly.[26] In addition, the partnership income from the development wells was also subject to reallocation among the partners after pay out. In both the registered and unregistered limited partnerships, the general partner was entitled to ¼ of the limited partners' share of production, or 17.5 per cent, after pay out. Additionally, at least in the registered limited partnerships, the general partner (CRC) was also entitled to ⅓ of the operator's share of the production from development wells after pay out.

3. Negotiation and Closing of Transactions in the 1972 Program. Bill Floyd represented the limited partnerships and CRC in negotiations with the operators in 1972. As various operators became aware of CRC's drilling program,[27] they brought to Floyd so-called prospect data sheets. A prospect data sheet normally provided a prospect's name, the depth to which a well would be drilled, the lease purchase price, the price of the no-out turnkey drilling contract, the percentage interest in the mineral

26. *E.g.*, if the Note was to be paid from 40 per cent of the Investors' share of production, the holder of the Note would receive 28 per cent of production.

27. The operators usually became aware of CRC through word-of-mouth within the oil and gas industry.

interest to be acquired, plus the size of the operator's hoped-for discovery if the well were successful. The operators would also give Floyd maps, geophysical records, seismic information, log records and other geological data. In setting forth facts on the prospect data sheets as to the amount and type of hydrocarbons being sought, the operators had an honest belief that such hydrocarbons might be found in the prospect. They fully intended Floyd to rely on these statements, although they also expected him to make an independent analysis using the materials they presented to him.

Floyd and the other geologists employed on behalf of CRC made an independent evaluation of each prospect. Floyd's review involved study of the geological maps, seismic data, etc., submitted with each prospect. As a consequence of this review, Floyd accepted, as to geology, only 5 to 10 per cent of the prospects offered to CRC in 1972.

If Floyd approved a prospect geologically, he would negotiate terms with the operators. As was mentioned above, each prospect data sheet set forth the lease purchase price and the cost of the no-out turnkey drilling contract, as proposed by the operator. In his negotiations Floyd attempted to obtain the lowest possible prices for the lease and no-out turnkey drilling contracts in order to benefit the Investors. Floyd was a competent and "tough" negotiator. He rejected on grounds of price approximately 30 per cent of the prospects approved geologically.

When Floyd negotiated prices with the operators, he did not receive an anticipated cost breakdown from the various operators.[28] The operators believed that the method by which they priced prospects was solely their

28. In the oil and gas industry, these cost breakdowns are normally referred to as authorizations for expenditure, or AFE's. Floyd did not receive AFE's from the operators.

concern, not Floyd's. The operators were aware, however, when they submitted their prospect data sheets to Floyd that they would receive in cash only a portion of both the lease purchase price and the drilling contract price. The lease purchase price and the drilling contract price were negotiated separately. In pricing the transactions the operators generally estimated their out-of-pocket drilling costs, their overhead and profit, and a risk factor. This estimate became the "cash portion" of the drilling contract price. In other words, if the drilling contract price were $100,000, the operator's own estimate of his costs, etc. would be $40,000. The note portion of the no-out turnkey drilling contract price would then be added to this estimate. The Note was usually equal to 150 percent of the estimated cash cost, or $60,000 in this example. In most instances, the operators hoped to meet all their costs, and make a profit, solely from the cash portion (*e.g.*, $40,000) of the consideration received from the Investors.[29] Of course, if problems arose in drilling a well, such as a blow out or an encounter with impenetrable material, it was unlikely that the cash portion would suffice to cover the operator's costs. Additionally, none of the operators expected the cash portion of the contract price to cover their costs if a completion were attempted.

There was no established pattern by which the various operators determined the lease purchase prices, but the operators all believed they were entitled to a considerable markup on the leases. The operators made substantial investments in the leases before they were conveyed to the partnerships, including a geological workup

29. At least one operator, Buttes Gas and Oil, calculated its total contract price as set forth on the prospect data sheet under a formula which made it unlikely that the cash portion would cover its cost and yield a profit. Buttes, however, did hope to recover its out-of-pocket costs from the cash portion.

and interpretation of this information by the operator's experts. The cost which the operator paid for the lease was only one factor which the operator considered in pricing the leases.

Without regard to how the various operators arrived at the lease purchase and drilling contract prices which they presented to Floyd on the prospect data sheets, all negotiations between Floyd and the operators concerned only the total prices. As found above, the lease purchase price and the drilling contract price were negotiated separately. In 1972 Floyd's specific instructions from CRC were that, having approved a prospect in terms of geology, Floyd was to engage in pricing discussions regarding only the total prices, without regard to the note portion versus the cash portion. Floyd was instructed to arrive at prices which he considered to be fair and reasonable.[30] At no time did Floyd and the operators first negotiate the cash portion, followed by addition of the Note. In these negotiations the operators were aware that a portion of the lease purchase price and the drilling contract price would be paid by means of a nonrecourse note. They were also aware of the completion option they would acquire and the no-out turnkey drilling obligation they undertook.

All negotiations between Floyd and the operators were at "arm's length." In each case the terms were commercially negotiated and were within a reasonable range of commercial practice. Due to the apparent paucity of "no-out turnkey contracts" outside these deals, it is not clear whether the markup of 150 percent from the drilling price (if payable in cash) would have been excessive compensation for the added risk. There was much sincere testimony that the price was fair even without re-

30. When, in rare instances, Soter negotiated on behalf of CRC, he followed a similar negotiation policy.

gard to the contingency, but due to lack of comparable deals, such testimony was largely conclusory in nature. However, at least when the nonrecourse Note is discounted for its contingent payability, it is clear that considerations on both sides for the drilling terms were commercially fair for both parties. For example, if the drilling contract price were $100,000, of which the cash portion was $40,000 and the note portion was $60,000, the $40,000 plus the nonrecourse Note and completion option was fair and reasonable consideration for the no-out turnkey drilling contract involved. Similarly, the lease purchase terms were also fair and reasonable. Moreover, the terms of the total contract were fair and reasonable. The "terms of the total contract" refers to all the rights and obligations exchanged by the parties. The operators received the cash portion of the total contract price, plus a nonrecourse note for the remainder of the contract price, and the completion option; in return, the operators sold the leases to the Investors and were obligated, on a no-out basis, to drill the test wells, and if a completion were attempted, to pay all completion costs plus reimburse the Investors for their lease purchase price plus tangibles. The operators viewed this transaction as an integrated whole. Significantly, none of the operators would have undertaken the no-out turnkey drilling obligation if they had been paid completely in cash [31] but without the completion rights. Moreover, at least two [32] of the operators did not consider the

31. *E.g.*, the operator would receive $100,000 in cash, rather than $40,000 in cash plus a note for $60,000, but no completion rights.

32. Only two operators (one of whom was a witness called by respondent) directly addressed this question. Another operator believed that the notes were important, but he did not specifically consider whether he would have entered into a transaction without the notes. A fourth operator, called as a witness by respondent,

transaction acceptable if they received only the cash portion plus the completion rights, but not the Note.[33]

In trades in the oil field, operators regularly demand large markups over their estimated cost. This was particularly true for no-out turnkey contracts, in which the operators were assuming all the risks in drilling the well. Accordingly, the fact that the nominal drilling contract price greatly exceeded the operators' estimated cost is not unusual for such a no-out turnkey drilling contract. Moreover, because CRC was the moneyed party, Floyd was negotiating from a very strong position in 1972. As one of the operators commented, "We were all starving to death." CRC was able to require the operators to take part of the nominal price for the drilling contract via a nonrecourse note because of this bargaining position. The operators were primarily concerned that the entire consideration which they received from CRC—cash, the Note and the completion option—was fair and reasonable compensation for the risks they undertook.

In order to verify that the drilling contract prices were fair and reasonable, CRC also instituted a "double check" on Floyd. Floyd was instructed to obtain from independent petroleum engineers opinions as to whether the drilling contract price for a proposed no-out turnkey drilling contract was fair and reasonable.[34] After CRC

32. (Cont'd.)
also stated that the notes were of value to him and that he wanted the notes as part of the transaction. On the other hand, in the Elpac transactions, discussed *infra*, some operators gave up the notes to a third party who assumed some of the risks of the no-out drilling obligation.

33. *E.g.*, the operator would have received $40,000 in cash plus the completion rights, but not the $60,000 note.

34. These letters also served as verification to CRC's auditors that the prices paid were fair and reasonable.

and an operator agreed upon a price for the contract, an independent engineer would be asked to opine whether the agreed-upon price was a fair and reasonable one. The engineers were not informed of the terms of the trade; that is, they did not know that a portion of the drilling contract price would be paid with a nonrecourse note, nor did they know about the completion option. Nine such independent petroleum engineers testified in this case. All of these engineers expressed the opinion that the total no-out turnkey drilling contract prices (i.e., the face cost of the contract, including the cash portion and the note portion) were fair and reasonable in light of the no-out drilling obligation assumed by the operators. While such opinions were necessarily conclusory, they at least support our conclusion that the overall terms of the transaction were not wholly afield from fair commercial practices.

After a package of prospects had been approved geologically and a price had been negotiated by Floyd and the operator, the contracts were sent to Soter for approval. Soter was not a geologist, and he did not review the geology of the prospect. Rather, Soter verified that the proposed package fit within CRC's financial planning, particularly if the package were expensive. Soter had the ultimate responsibility as to whether a package was accepted or not, and sometimes he overruled decisions which Floyd had reached.

Once a package was approved, a formal closing was held. These closings followed instructions which Soter had issued. A typical closing, for a transaction in which the lease purchase and turnkey drilling contract prices totaled $100,000, went through the following steps. First, the operator would obtain, usually through a one-day loan from a bank, the note portion (*e.g.*, $60,000) of the contract price. The operator would then "loan" this $60,000 to the partnership; in return, the operator

would receive the Loan Agreement, the Note, the Mortgage and the Joint Venture Agreement. Next, the operator would deliver the Lease Purchase and Turnkey Drilling Agreement to the partnership, in return for which the operator would receive the total contract price (*e.g.*, $100,000) in cash. The operator would then repay to the bank the $60,000 which he had borrowed.[35] At the closing the operator had received the $60,000 nonrecourse Note, the Mortgage, and the Loan Agreement (including the Joint Venture Agreement and the completion option), plus $40,000 cash, and the partnership had received the leases plus the operator's no-out turnkey drilling obligation.

CRC insisted that the closings follow this pattern on the advice of its accountants. Originally CRC had simply given the operators a check for the cash portion plus a note in the amount of the note portion, but CRC's accountants disapproved of this format. The accountants felt that it was important to have the entire contract price paid in cash in order to create an "audit trail." CRC followed its accountants' advice and arranged for the check swap in which, in a $100,000 contract, CRC would get a check from the operator for $60,000 and would give back a check to the operator for $100,000. CRC did not believe that either the check swap or the "loan" format had any economic significance, nor did it; this form was followed merely to satisfy its accountants. CRC understood that, in substance, it was giving the operator the cash

35. In the transactions involving CRC and Emerald Petroleum or Emerald Producing, the operators did not follow this pattern in that the operators never "loaned" money to the Investors. Rather, the operators simply received the nonrecourse Note, the Mortgage, the Loan Agreement (including the completion option) and the cash, and gave to the partnership the leases and the no-out turnkey drilling obligation.

portion of the total contract price plus a nonrecourse note for the remainder of such price.

Similarly, the operators did not believe that they had actually "loaned" money to CRC in the traditional sense. The operators were aware that, in substance, they received the cash portion of the total contract price plus the nonrecourse Note. The operators considered the payments due under the Loan Agreement and the nonrecourse Note to be a production payment. A production payment, generally speaking, is an obligation of an operator or an owner of a working interest in an oil or gas well to pay a specified amount of money only out of a specified part of the production of the well.[36] Normally the holder of the production payment has no right to foreclose on the property if not paid; in this case, the holders (i.e., the operators) could foreclose on the mineral leases and property thereon. Nevertheless, the operators expected that if all the wells in a package were dry holes, the Note would have a de minimis value.[37] As a practical matter, as the operators understood, the only economically significant security for the nonrecourse Notes was oil and gas, if found, in the prospects which were to be drilled. Accordingly, the operators considered the nonrecourse Note to be a production payment which they received as part of the consideration (along with the cash portion and the

36. For tax purposes, "production payments" are defined in section 1.636-3, Income Tax Regs.

37. Security for the Note was a percentage (usually 75% of the Investors' mineral interest plus a percentage (usually 75%) of the value of the equipment remaining on the prospect. If a prospect yielded a dry hole, both this equipment and the mineral interest were of minimal, if any, value. If a completion were attempted, the equipment on the prospect would have value, but under the Joint Venture Agreement the completing operator had the first lien on this equipment.

completion option) for the leases and their no-out turnkey drilling obligation.[38]

4. *The Elpac Transactions.* Numerous transactions entered into between CRC and the operators in 1972 were materially different from the "standard" transaction in that a third party, Elpac, Inc. ("Elpac"), assumed the "lender's"[38a] role in the transaction. The transactions in which Elpac participated involved three operators—McMoRan, Gibraltar Oil Corporation ("Gibraltar") and Sinclair Development Company ("Sinclair").

Elpac was a publicly-held California corporation. In 1969 and 1970 it underwent a reorganization in bankruptcy, and as a result F. L. Cappaert became its principal shareholder. Cappaert was on the board of directors of McMoRan and was also a major shareholder in McMoRan. Upon emerging from its reorganization Elpac had a net operating loss carryover in excess of $8 million. This net operating loss carryover was considered to be a valuable asset since it was believed that it could be used as a means of sheltering income which Elpac hoped to generate in its business activities. Although Elpac had previously been engaged primarily in the electronics business, Cappaert acquired Elpac with the idea of expanding it into the oil and gas business because he foresaw a coming energy shortage.

In 1970 McMoRan dealt directly with CRC in that McMoRan acted as the operator/lender in its transactions with CRC and the limited partnerships. In 1971 McMo-

38. The operators were bullish on their prospects. They expected to be paid on these Notes and they expected such payment to be made from the reserves found. If reserves of the magnitude set forth on the prospect data sheet were discovered, it was likely that the Notes would be paid before exhaustion of the reserves.

38a. The "lender" is the party who receives the nonrecourse Note used in these transactions.

Ran decided it did not want to act as the lender in its transactions with CRC, although it still wanted to do business with CRC. McMoRan had two primary reasons for not wishing to be the lender. First, McMoRan did not consider the lender's role to be as advantageous after CRC eliminated the conversion right in 1971. Second, McMoRan had a sufficient net operating loss carryover in 1970 to absorb the Notes into income, but did not have this carryover in 1971. Accordingly, McMoRan decided not to enter into a transaction in which it would incur the tax liability represented by the Notes. However, CRC informed McMoRan that CRC was unwilling to enter into drilling programs with McMoRan unless a portion of the consideration McMoRan received was paid with the nonrecourse Notes. Accordingly, in order to continue working with CRC, McMoRan sought a net operating loss carryover company to take the Notes.

Messrs. Rankin and Moffett on behalf of McMoRan and Mr. Graham on behalf of Elpac negotiated an arrangement under which Elpac agreed to be the "lender" in transactions with CRC. Elpac entered into the transactions not for the benefit of McMoRan but, rather, for its own benefit.[39] Elpac wanted to enter into the oil and gas business, and it believed that the nonrecourse Notes presented it with an opportunity to benefit from oil and gas exploration. Elpac was aware that only a net operating loss carryover company could afford to acquire these nonrecourse Notes, since receipt of the Notes was believed to generate substantial income for income tax purposes without generating cash to pay those income taxes. Accordingly, Elpac believed that acceptance of the Notes would enable it to participate in the exploration program of a successful operator, McMoRan, and benefit from

39. CRC played no role whatsoever in the introduction of Elpac into these transactions.

the production, if any, at the cost of using up its net operating loss carryover plus the assumption of certain risks. When it entered these transactions, Elpac hoped that the Notes would be paid.

Elpac's participation in transactions with McMoRan and CRC generally assumed the following pattern. First, McMoRan and CRC would negotiate the price of a Lease Purchase and Turnkey Drilling Agreement identical to the agreements in the "standard" transaction. The agreement reached would be identical from CRC's point of view, since CRC would receive the leases and a no-out turnkey drilling agreement in return for cash, a nonrecourse Note, a Mortgage and a Joint Venture Agreement indistinguishable from the agreements entered into with other operators.[40] After McMoRan and CRC reached an agreement, the following steps were taken simultaneously. McMoRan would assign to Elpac its oil and gas leases for the package of prospects. Elpac would deliver its check to McMoRan for the note portion of the partnership's total contract price (i.e., lease purchase and drilling contract prices), and Elpac would receive back from McMoRan the nonrecourse Notes. Elpac would assign the leases to the partnership, commit itself to perform the no-out turnkey drilling contract, and receive a partnership check for the total price set forth in the Lease Purchase and Turnkey Drilling Agreement. Elpac also received the completion option. Elpac would deliver its check for the cash portion of the total contract price, plus the completion option, to McMoRan in return for McMoRan's promise to drill the test wells. After the closing, Elpac had received the nonrecourse Notes and the rights thereunder, McMoRan (which was obligated to drill the test

40. In at least one Elpac transaction the operator's share under the Joint Venture Agreement was based on a ratio of costs incurred similar to the ratio used in the 1970 drilling program.

wells) had received the cash portion of the Lease Purchase and Turnkey Drilling Agreement price plus the completion option, and the partnership had obtained the leases and a no-out turnkey drilling contract from Elpac under the terms identical to those of the "standard" transaction. As in the "standard" transaction, in the Elpac transactions the lease purchase and drilling contract terms were within a reasonable range of commercial practice.

Elpac was required by a separate agreement with McMoRan to share with McMoRan any cost overruns.[41] That is, to the extent that McMoRan's out-of-pocket cost (representing lease costs, actual drilling costs and third party service costs) exceeded the cash portion of the total contract price (i.e., lease purchase and drilling contract prices), Elpac was obligated to pay McMoRan 50 per cent of such excess. In essence, even through McMoRan promised to drill the wells for Elpac, Elpac still had substantial risk, including particularly its promise to share any cost overruns with McMoRan and Elpac's total liability to the Investors. Because of these risks, Graham of Elpac reviewed all the contracts to see if any prospects were too risky from Elpac's point of view.

The drilling agreement entered into between Elpac and McMoRan obligated McMoRan to drill the wells which Elpac was required, under its no-out turnkey drilling contract, to drill for CRC. However, McMoRan did not assume Elpac's full obligation to CRC; rather, McMoRan simply promised to drill the wells for Elpac at an agreed-upon price and furnish Elpac with one induction electric log. In contrast, Elpac's agreement with

41. Originally, Elpac did not agree to share any cost overruns. In 1972, however, the agreements between Elpac and McMoRan were modified to provide for such sharing. This change was made at the request of CRC. This change was made to conform to CRC's belief that the Elpac-McMoRan agreement provided for cost sharing rather than constituting a double turnkey.

CRC not only required Elpac to drill the well but, additionally, specified in great detail the site preparation, environmental costs,[41a] related drilling costs, etc. which Elpac was required to bear. Elpac also promised to "furnish all logs, cores and tests necessary to evaluate each well to the extent a prudent operator in the area could determine whether or not a completion attempt should be made thereon." In short, Elpac's drilling obligation to CRC was broader than McMoRan's obligation to Elpac.

McMoRan was not the only operator with which Elpac entered into such agreements; Elpac also entered into similar contractual agreements with Gibraltar and Sinclair. These operators similarly negotiated the terms of the lease purchase and turnkey drilling agreement with CRC and then brought Elpac into the transaction.[42] The contractual agreements between Elpac and these operators were, essentially, identical to the agreements between Elpac and McMoRan. That is, Elpac bore the same risks in its contracts with Gibraltar and Sinclair that it bore in its contracts with McMoRan. However, there was one substantial modification in the Gibraltar and Sinclair deals. In addition to assigning the completion rights to those operators, Elpac also assigned to them a production payment, usually equal to 15 per cent of the note portion of the total contract price, which was payable out of receipts under Elpac's interest in the Notes. Elpac considered this

41a. These environmental costs included all crop and surface damage. Additionally, if any problems were encountered in drilling a well, the environmental costs could be enormous, particularly if the well were offshore. The record does not disclose whether any Elpac wells were offshore.

42. As in the Elpac-McMoRan transactions, it was the operators, not CRC, who contacted Elpac. Elpac was introduced to Sinclair and Gibraltar by individuals connected with McMoRan.

production payment which it gave to Gibraltar and Sinclair to be of value, and this contractual agreement was reached by negotiations between Elpac and these operators.

In entering these transactions, Elpac expected that the transaction would result in ordinary income to Elpac for tax purposes to the extent of the face amount of the Notes (but not for financial accounting purposes) which income Elpac was willing to absorb. Elpac knew that it had no recourse against the Investors on the Notes, and it believed that "if the wells drilled on the prospects are dry holes, Elpac [will receive] no payments on the notes, and its security is valueless, resulting in no profit to Elpac." Elpac planned, when the drilling was completed, to deduct any then excess of the face amount of the Notes over the value, if any, of its interests in discovered minerals.

5. The Duquesne-Kiowa-TNT Transaction. In 1972 Patrick Taylor started in the oil and gas operating business as president of TNT, Inc. ("TNT"). Taylor was an engineer who was just getting into oil operating, and he had no source of outside funds. TNT had acquired several mineral leases which were about to expire if not drilled, but it lacked the funds to drill these prospects.

Jerry Freel, who was president of Kiowa Minerals Company ("Kiowa"), was a friend of Taylor's. Kiowa was an oil and gas operator with offices in Houston. On September 13, 1972, Taylor submitted a prospect (the Singer prospect) to Freel. TNT submitted a price of $75,000 for testing the Singer prospect, and TNT proposed that it retain a 1/16th working interest for bearing 1/16th of the costs. In other words, Kiowa could obtain 15/16th of the working interest in the prospect, which would be drilled and tested by TNT, for $70,312. The proposed contract was not a no-out turnkey contract;

TNT reserved the protections of a Gulf Coast Clause. Taylor believed this was a minimal price, but he proposed it because the leases were about to expire and he wanted to make a reputation for himself.

Freel accepted Taylor's proposal, but Freel also did not have the money needed to test the Singer prospect. Like many other operators, Kiowa had very little money in 1972. In order to obtain funds to test the Singer prospect, Freel contacted CRC and negotiated with it.[43] Freel negotiated a lease purchase price of $10,000 and a no-out turnkey drilling contract price on the Singer prospect of $204,125, of which 40 percent (or $85,650) was to be paid in cash and the remainder ($128,475) was to be paid with a nonrecourse note. The total contract price agreed to by Freel and CRC was within a reasonable range of commercial practice for a no-out turnkey arrangement. Charles Stokley, an independent petroleum engineer, issued a credible albeit conclusory opinion that the price was fair, and there was no credible evidence introduced by respondent to the contrary.

Freel then returned to Taylor and told Taylor that he (Freel) needed a no-out turnkey contract for the Singer prospect at the agreed-upon price of $75,000 between Freel and Taylor. At first Taylor objected, but eventually he agreed to drill the well on a "no-log, no pay contract" basis for $75,000.[44] Taylor was willing to ac-

43. Taylor played no part in the negotiations with CRC; he was not aware of the terms of the agreement negotiated by Freel and CRC. Taylor's only contact with CRC was at the closing for this transaction. Taylor did not originally attempt to contract directly with CRC because he knew that CRC did not know who he was; later, after Freel contacted CRC, Taylor believed that it would have been unethical for him to deal directly with CRC.

44. A no-log, no-pay contract is different than a no-out turnkey contract; in a no-log, no-pay contract the operator can simply walk away from the prospect and not get paid, while in a no-out turnkey

cept this change because he "very much wanted to drill the well" and because he had money invested in the Singer prospect. Moreover, TNT had almost no assets; Taylor knew that if he could not satisfy this drilling contract because the well cost too much, TNT would fail as a corporation. Accordingly, Taylor believed that Freel was taking most of the risk of the no-out provision of the drilling contract, because if "[TNT] had failed, and could not drill the well, and [Freel] did not pay [TNT], then [Freel] would have been stuck ° ° ° . So [Freel] would have had to drill the well there to the limit of his assets." Taylor believed that a fair price for a no-log, no-pay drilling contract on the Singer prospect, in light of the risks involved, was three times what he was paid, or $225,000.

Although Freel had negotiated a drilling contract with CRC, Freel did not want Kiowa to receive the nonrecourse Note.[45] Accordingly, Freel contacted Leonard Carr of Duquesne Natural Gas Company ("Duquesne"). Duquesne was a Pennsylvania corporation with offices in Houston, Texas; it was primarily engaged in the manufacture of pumps and compressors and in the operation of barge-mounted offshore drilling rigs. Prior to 1972, Duquesne had also been an oil and gas operator, but it had ceased such business by 1972. Duquesne had a substantial net operating loss carryover.

In this transaction, Duquesne assumed the "lender" role which Elpac had performed in transactions with

44. (Cont'd.)

contract the operator must continue drilling until casing point is reached, no matter what the cost.

45. We do not know the reason why Freel did not want the Note; respondent subpoenaed Freel as a witness, and he appeared at the trial, but respondent did not call him. The record does not disclose whether Kiowa had any net operating loss carryovers.

McMoRan, Gibraltar and Sinclair. There was, however, a significant difference between this transaction and the Elpac transactions—Kiowa expressly assumed all of Duquesne's obligations under the no-out turnkey drilling contract. In other words, in contrast to the Elpac transactions in which the "lender," Elpac, shared half of the operators' risks, in the Duquesne-Kiowa transaction the contractual risks were expressly assumed by Kiowa. However, there was no novation of the Duquesne-CRC contract, and Duquesne remained residually liable. Duquesne was willing to enter this transaction because it believed that "the odds are we will lose instead of winning on such a deal, however, the loss would be minimal and the gain could be substantial." The primary risk which Duquesne knowingly accepted was that it could have to perform on the drilling obligation. This risk existed despite Kiowa's assumption of Duquesne's obligation to CRC, because Kiowa had few assets to use to pay for drilling if any problems were encountered. In other words, if problems were encountered in drilling the Singer prospect, since neither TNT nor Kiowa had assets to speak of, Duquesne could have had to pay for the drilling despite the contractual obligations of TNT and Kiowa. Additionally, Duquesne had to pay a state corporate income tax to Louisiana of 4 percent of the face amount of the Notes received.[46]

In the transaction with CRC, TNT assigned to Duquesne the Singer lease, which in turn Duquesne assigned to CRC. Duquesne entered into a no-out turnkey drilling contract with CRC in return for the total contract price ($85,650 plus a $128,475 nonrecourse note), of which it retained the note portion and assigned to Kiowa the cash and all other rights, including the completion

46. Louisiana corporate tax law does not provide for net operating loss carryovers.

option. Kiowa expressly assumed Duquesne's obligations under the no-out turnkey drilling contract. In sum, Duquesne retained only the Note, the income from which it offset with its net operating loss carryover. Kiowa assumed Duquesne's no-out turnkey drilling obligation and received the $85,650 cash portion of the contract price plus the completion option. Kiowa, in turn, entered into a no-log, no-pay contract under which TNT actually tested the Singer prospect for $75,000, $10,000 less than the cash received by Kiowa. This may not have been a fair price for the no-log, no-pay contract because of TNT's disadvantageous bargaining position. TNT believed it was grossly underpaid.

Before this transaction closed, Duquesne obtained a three-day loan from a bank in the amount of the note portion of the contract price. At the closing, Duquesne issued a check to CRC in the amount of the note portion of the contract price, and in return received from CRC a check in the full amount of the contract price plus the Note. Duquesne also gave CRC the leases and its no-out turnkey drilling obligation, which had been assumed by Kiowa. At the closing, an attorney for CRC specifically requested that Taylor, Freel and the representative from Duquesne not discuss in his (the attorney's) presence the details of the Duquesne-Kiowa-TNT arrangement.

6. Success of the 1972 Drilling Program. The operators drilled and tested all wells as required under the Lease Purchase and Turnkey Drilling Agreements entered into in 1972. All the operators hoped to cover their drilling costs, including overhead, with the cash portion of the drilling contract prices received from the Investors; some were successful in satisfying their drilling obligations for only the cash portion, others were not. The record does not disclose how many were not.

Of the twenty-four packages participated in by Coral I and Coral II, eleven of the packages resulted in all dry holes which were plugged and abandoned. Of the twenty-eight packages participated in by CRC individually, thirteen of the packages resulted in all dry holes which were plugged and abandoned. Additionally, in many other packages one or more wells were plugged and abandoned, although in all of the other packages at least one well was completed as a producing well.

Despite the large number of dry holes drilled, sizable reserves of oil and gas were found. The total partnership investments in the 1972 program were $35,000,000 in cash and $52,000,000 in nonrecourse Notes.[46a] As of July 1, 1976, proven reserves in the ground from the 1972 program had a value in excess of $68,000,000. This amount is in addition to all oil and gas extracted before July 1, 1976. Out of this amount, production taxes and transportation costs of approximately $4,000,000, operating costs of approximately $11,300,000, and other deductions of $2,500,000 could be expected to be paid by 1990. Additionally, payments of principal and interest on the Notes in the amount of approximately $9,000,000 would be made from total production. Accordingly, after all of these deductions, proven reserves as of July 1, 1976, which would be payable to the partnerships, had a value in excess of $40,000,000. Discounted at 10 percent to present worth of the future stream of net income from production from the wells, CRC's proven reserves had a present worth as of July 1, 1976 of $24,087,148.

46a. The typical mixture of cash and nonrecourse note for a given package of prospects is discernible from the table below. The packages listed are those comprising the Coral I and Coral II limited partnerships as well as those packages in which CRC participated as an individual investor. (See pages 24 and 25 *supra.*) These represented only a portion of CRC's 1972 portfolio:

46a. (Cont'd.)

Coral I and Coral II

Package Number	*Name of Operator*	*Cash Portion*	*Nonrecourse Note*	*Total*
72-1	McMoRan (Elpac)	$ 182,160	$ 273,240	$ 455,400
2	Powers (Poco)	417,200	625,800	1,043,000
3	Western States	675,000	452,133	1,127,133
4	McMoRan (Elpac)	154,440	231,660	386,100
5	McMoRan (Elpac)	119,400	179,100	298,500
6	McMoRan (Elpac)	227,000	340,500	567,500
7	McMoRan (Elpac)	449,223	673,850	1,123,073
8	Gibraltar (Elpac)	258,800	388,200	647,000
9	Dynamic	306,000	459,000	765,000
10	Emerald	520,000	780,000	1,300,000
11	Gibraltar (Elpac)	196,000	294,000	490,000
12	McMoRan (Elpac)	575,224	862,866	1,438,090
13	Sinclair (Elpac)	377,620	566,430	944,050
14	Powers (Poco)	312,600	468,900	781,500
15	Gibraltar (Elpac)	229,400	344,100	573,500
16	McMoRan (Elpac)	480,424	720,636	1,201,060
17	McMoRan (Elpac)	182,160	273,240	455,400
18	McMoRan (Elpac)	182,160	273,240	455,400
20	Emerald	654,800	982,200	1,637,000
22	Birthright	487,200	730,800	1,218,000
42	Gibraltar (Elpac)	208,225	312,337	520,562
31	McMoRan (Elpac)	1,085,184	1,627,776	2,712,960
32	Patrick	99,600	149,400	249,000
96	Arriba	417,097	625,645	1,042,742

46a. (Cont'd.)

CRC's Individual Investments

Package Number	*Name of Operator*	*Cash Portion*	*Nonrecourse Note*	*Total*
72-35	Emerald	$581,800	$ 872,700	$1,454,500
37	Duquesne	423,275	634,912	1,058,187
43	Gibraltar (Elpac)	422,000	633,000	1,055,000
44	Cane	390,337	555,855	946,192
45	Cane	316,209	444,664	760,873
51	Patrick	458,300	687,450	1,145,750
52	Patrick	543,200	814,800	1,358,000
61	Nor-Am	193,144	277,938	471,082
63	Triton	192,800	289,200	482,000
67	Gibraltar (Elpac)	349,250	523,875	873,125
68	Nor-Am	488,662	703,194	1,191,856
69	Sinclair (Elpac)	256,500	384,750	641,250
70	Corpening	101,875	152,812	254,687
72	McMoRan (Elpac)	576,550	864,825	1,441,375
75	Nor-Am	927,641	1,334,905	2,262,546
76	Scoggins	185,461	278,191	463,652
77	McMoRan (Elpac)	496,660	744,990	1,241,650
78	McMoRan (Elpac)	493,168	739,752	1,232,920
79	McMoRan (Elpac)	401,120	601,680	1,002,800
80	McMoRan (Elpac)	429,400	644,100	1,073,500
81	McMoRan (Elpac)	283,140	424,710	707,850
82	McMoRan (Elpac)	437,600	656,400	1,094,000
83	McMoRan (Elpac)	120,000	180,000	300,000
84	McMoRan (Elpac)	109,500	164,250	273,750
85	McMoRan (Elpac)	115,000	172,500	287,500
86	Tech-Sym	225,530	338,295	563,825
87	McMoRan	193,159	289,723	482,882
88	Gibraltar (Elpac)	273,800	410,700	684,500

An example of a successful operation under CRC's 1972 drilling program was that of Patrick Petroleum Company ("Patrick"). In 1972 CRC invested approximately $7,800,000 with Patrick, which amount includes both the cash and the note portion of the total contract prices, to drill seven packages. As of January 1, 1979, CRC and the partnerships had received back approximately $12,000,000, and the reserves in the ground discovered by Patrick had an estimated value of $40,000,000. Coral I and Coral II were investors in one Patrick package in 1972, and CRC was an investor in two Patrick packages.

Petitioner Brountas invested $11,000 in the Coral I limited partnership with the purpose of profiting from his investment. As of January 1, 1979, he had received cash repayments of approximately $3,000. Additionally, the value of his interest in Coral I, as reflected in the reserves of oil and gas in the ground as of January 1, 1979, was in excess of his original cash investment ($11,000) in the partnership.

7. *Deductions Claimed for Exploration and Development.* Coral I, Coral II and CRC claimed intangible drilling and development cost deductions for 1972 as follows:

Coral I	$1,533,871
Coral II	1,543,614
CRC	662,454

Each Coral partnership and CRC validly elected, pursuant to section 263, to deduct such intangible drilling costs. The amount claimed as intangible drilling and development costs was the aliquot share of the total price of the turnkey drilling contracts (cash and note portions) for the packages in which Coral I, Coral II and CRC had direct interests. The portion of the total cost of the

Lease Purchase and Turnkey Drilling Contracts which was allocable to acquisition of the leases was not deducted as an intangible drilling and development cost.

C. Other Issues.

1. Interest. The nonrecourse Notes which were received as part of these transactions called for interest at the rate of 6½ percent per annum. Coral I, Coral II and CRC claimed interest deductions with respect to these Notes in 1972 as follows:

Coral I	$ 32,743
Coral II	33,027
CRC	961

2. Advanced Royalties. Coral I, Coral II and CRC claimed deductions in 1972 for "advanced royalties" as follows:

Coral I	$ 66,319
Coral II	66,066
CRC	55,775

The "advanced royalties" were equal to the note portions of the stated lease purchase prices under the Lease Purchase and Turnkey Drilling Agreements which were entered into with various operators. These portions of the Notes (lease price) had the same security as the portions of the Notes allocable to drilling. Each Note was secured by a portion of the production, if any, from the package of prospects, plus a specified percentage of the mineral lease and equipment thereon. If the operator exercised its completion option, this portion of the Note (as part of the lease cost) was to be reimbursed to the partnership. Such reimbursement was accomplished by cancellation of this portion of the Note, as well as a cash reimbursement

of the cash portion of the lease purchase price. If such reimbursement of the note portion of the lease cost were made, then the accountant for CRC or the limited partnerships credited this amount as a loan reduction. If the prospects generated a dry hole, these "advanced royalties" would not be reimbursed.

3. *Management Fees.* On their partnership information returns (Forms 1065) for 1972, Coral I and Coral II claimed deductions for management fees of $185,946 and $187,152, respectively. Investors in Coral I and Coral II paid as a management fee to the general partners, of which CRC was one, an amount equal to 9 percent of total program drilling commitments (i.e., total contract prices). Inasmuch as total drilling commitments were approximately twice total subscriptions from the limited partners, the management fee was, in fact, about 18 percent of the limited partners' subscriptions. This fee was in lieu of any allocation of overhead expenses of the general partners to the 1972 program and entitled the partnership to all necessary services of the general partners' personnel and equipment. This fee was in addition to the general partners' interest in production from the program (i.e., ¼ of the partnerships' interest after pay out).

The fee charged by CRC was comparable to the management fees imposed by other oil and gas exploratory drilling ventures in 1972. These fees were intended to compensate CRC for its services as general partner; the fees were credited to CRC's capital account in the partnerships and paid to CRC as soon as credited. Although the partnerships were forbidden to pay commissions on the sales of partnership interests, CRC used these fees to pay brokerage commissions on the sales of limited partnership interests in Coral I and Coral II. Such brokerage commissions amounted to 8 percent of the investor subscriptions in Coral I and Coral II.

4. Abandonment Losses. Coral I, Coral II and CRC claimed abandonment losses as follows in 1972:

Coral I	$286,473
Coral II	288,674
CRC	18,533

These claimed losses arose from the alleged abandonment of the mineral leases with respect to prospects which had been tested. The value of the leases was determined by the lease purchase prices paid to the operators.

The partnerships and CRC established a policy for abandoning leaseholds which depended entirely upon a geological determination whether the lease had further geological merit. If a test well were a dry hole, a geologist for CRC determined whether or not to abandon the lease. A lease was deemed entirely abandoned when CRC or the partnerships ceased paying delay rentals for that lease. In other instances, leases would be "partially abandoned," when the geologist would determine that a portion of a lease on which the test well was productive should be abandoned, or when the geologist determined to retain some or all of a lease despite a dry test hole because of the possibility of drilling another well or farming out the prospect to a third party.

After this geological determination was made, the geologist (usually Floyd) would contact CRC's accounting staff and inform them whether all or any portion of a leasehold was to be abandoned. When all or a portion of a lease was retained, delay rentals for the entire lease would be paid. These delay rentals were nominal in amount. However, the record discloses no instance in which another well was drilled or such a prospect was in fact farmed out or ever produced any mineral. The indicated percentage of the leases to be abandoned would

then be transferred from the capital account to the expense account as an abandonment loss. Such abandonment losses were then reported by the partnerships and claimed by petitioners on their tax returns.

5. Income from Cancellation of Indebtedness. When all the leases for the prospects in a package were "abandoned" entirely, the nonrecourse Note which was secured by the leaseholds was considered as worthless by the partnerships. Thus, as long as CRC continued paying delay rentals with respect to at least one lease in a package in which all the prospects were dry holes, the Note with respect to the package would not be "cancelled." A Note would be considered cancelled, and cancellation of indebtedness income recognized by the partnerships, only when the geologist concluded that the payment of delay rentals for all prospects in a package should cease. The delay rentals required to retain a leasehold were relatively minimal. The effect of CRC's reliance on a geological determination as to when leaseholds should be abandoned was to defer recognition of the cancellation of the indebtedness on the nonrecourse Notes when a package yielded all dry holes. In 1973, nominal delay rentals were paid with respect to at least eight packages after all the wells in the package were known to be dry holes.

D. Respondent's Determinations

On his income tax return for 1972, Brountas claimed a loss from Coral I in the amount of $18,919. He claimed a loss in 1973 of $1,882. On its corporate income tax returns for 1972 and 1973, CRC claimed losses from Coral I of $47,294 and $4,705, respectively. CRC claimed losses from Coral II in 1972 and 1973 of $47,259 and $4,737, respectively. These losses claimed by Brountas and CRC were their distributive shares, as limited partners, of the losses reported by Coral I and Coral II on Form 1065.

In his statutory notices, respondent disallowed part of the deductions for intangible drilling and development costs ("IDCs") claimed in 1972 by Coral I, Coral II and CRC. The amounts of IDC deductions disallowed by respondent consisted of the amounts attributable to the note portions of the drilling contact prices. Respondent disallowed IDC deductions of $847,349 for Coral I, of which $12,531 was allocable to petitioner Brountas and $20,866 was allocable to CRC; respondent disallowed IDC deductions of $866,371 for Coral II, of which $20,814 was allocable to CRC; and respondent disallowed CRC's claimed direct (nonpartnership) deduction for IDC of $397,474.

Respondent disallowed the entire amount of interest expense deduction claimed by Coral I, Coral II and CRC for 1972. Respondent also disallowed in their entirety the amounts claimed as abandonment losses by Coral I, Coral II and CRC, and respondent disallowed in their entirety the deductions claimed for advanced royalties by Coral I, Coral II and CRC. Respondent disallowed $90,800 and $91,440 of the management fees deductions claimed in 1972 by Coral I and Coral II, respectively. The amount of management fees disallowed by respondent is equal to 8 percent of the limited partners' subscriptions. Petitioner Brountas' and CRC's shares of the disallowed deductions of Coral I and Coral II for 1972 were as follows:

Petitioner	*Deduction*	*Coral I*	*Coral II*
Brountas	IDC	$ 8,834.22	
	interest	288.50	
	abandonment losses	2,524.11	
	advance royalties	584.35	
	management fees	800.04	
		$13,031.22	
CRC	IDC	$20,868.00	$20,814.00
	interest	722.00	722.00
	abandonment losses	6,320.00	6,314.00
	advanced royalties	1,463.00	1,445.00
	management fees	2,003.00	2,000.00
		$31,376.00	$31,295.00

With respect to 1973, respondent determined that CRC received income from forgiveness of indebtedness related to Coral I in the amount of $27,895, and with respect to Coral II respondent determined income from forgiveness of indebtedness of $27,871. Respondent further determined CRC's income from forgiveness of indebtedness from other ventures was $399,461 in 1973. Respondent determined that petitioner Brountas realized income from forgiveness of indebtedness related to Coral I of $5,647.90 in 1973. The basis of respondent's determinations was that if this or some other court should hold that the nonrecourse loans had economic substance, then the loans had been forgiven in 1973 and the partners were in constructive receipt of ordinary income in the amount of the loans. Respondent determined that Coral I's, Coral II's and CRC's entire nonrecourse indebtedness outstanding as of December 31, 1972, had been cancelled in 1973. CRC had reported its income from cancellation of indebtedness as ordinary income, while the individual limited partners (such as Brountas) had reported their income as capital gains.

Respondent determined that all or part of CRC's (but not Brountas') payment of tax in 1972 was due to fraud.

Ultimate Findings of Fact

The nonrecourse Notes which were included in these transactions had value and commercial reality and were not shams.

Transactions between CRC (on behalf of itself and the other investors) and the various operators followed a general pattern. In each case the operator would submit to CRC a package of geological prospects to be drilled, along with the lease purchase cost and the drilling contract cost for the proposed package. The operators were aware that they would receive cash and a nonrecourse Note; the cash/note ratio was usually 40/60. The op-

erators were also aware that they would receive a completion option, which would entitle them to a share of production if they paid the costs of completing the well and reimbursed certain costs to the Investors.

CRC and the operators engaged in arm's-length negotiations as to the lease purchase and drilling prices. The drilling contract terms agreed to were always fair and reasonable in light of the contingent nature of part of the price and the risks undertaken by the operator in a no-out turnkey drilling contract. The lease purchase terms were also fair and reasonable again considering the contingent nature of part of the price. Moreover, the total consideration which the Investors gave to the operators—cash, the Note and the completion option—was fair and reasonable compensation for the leases and the services performed and contributions made by the operators. The transactions were integrated wholes, and the Notes were an integral part of these transactions.

The Notes were nonrecourse and were secured, in economic reality, only by the oil and gas found. The Notes were cross-collateralized, so that production from any one prospect within a package secured the entire Note. Although the Notes were also secured by the equipment on the leasehold and the mineral interests, if all the test wells in a package produced dry holes, this security had de minimis value. If all the wells in a package were plugged and abandoned, the nonrecourse Notes became worthless. The operators viewed the Notes as substantially equivalent to production payments, which are rights to a specified amount of money only out of a specified portion of the production of one or more wells.

OPINION

I. *Intangible Drilling and Development Costs.*

The first issue for decision is whether Special Coral 1972 Drilling Venture I ("Coral I"), Special Coral 1972

Drilling Venture II ("Coral II") and CRC Corporation ("CRC") are entitled to deductions for intangible drilling and development costs in excess of the cash consideration which they paid to the various operators. In 1972 petitioner Paul Brountas ("Brountas") was a limited partner in Coral I, and petitioner CRC was both the general partner and a limited partner in Coral I and Coral II. CRC also invested directly in drilling operations for its own account. As set forth in our Findings of Fact, these limited partnerships raised money which was invested with various oil and gas operators in exploratory drilling programs. In return for a mineral lease and a no-out turnkey drilling obligation, the operators received consideration of three types: (1) the cash portion of the total "contract price" for Lease Purchase and Turnkey Drilling Agreement; (2) a nonrecourse note, payable from production on any of a group of prospects, for the note portion of the total "contract price"; and (3) the completion option, under which if a well appeared productive, the operator could, by completing it and repaying the cost, recapture part of the leasehold interest.

On their returns petitioners claimed losses resulting largely from deductions for intangible drilling and development costs ("IDCs") claimed by Coral I, Coral II and CRC.[47] The IDC deductions claimed were in the

47. The losses claimed by petitioners exceeded their cash contributions to the partnerships. For example, in 1972 petitioner Brountas contributed $10,000 to Coral I for his limited partnership interest therein; he claimed a loss from Coral I in 1972 of $18,919. Petitioners readily concede that the 1972 Drilling Program constitutes what is commonly called a "tax shelter," since it purportedly yielded to the investors deductions in excess of cash contributed in the first year.

This type of tax shelter was addressed by Congress in the Tax Reform Act of 1976, Pub. L. No. 94-455, 90 Stat. 1520. Specifically, Congress adopted at-risk provisions which effectively barred individual taxpayers (such as petitioner Brountas) from deducting

47. (Cont'd.)

losses in excess of the amounts for which the investor is at risk. As adopted in 1976, section 465, which was generally effective for losses attributable to amounts paid or incurred in taxable years beginning after December 31, 1975, provided:

SEC. 465. DEDUCTIONS LIMITED TO AMOUNT AT RISK IN CASE OF CERTAIN ACTIVITIES.

(a) General Rule.—In the case of a taxpayer (other than a corporation which is neither an electing small business corporation (as defined in section 1371(b)) nor a personal holding company (as defined in section 542)) engaged in an activity to which this section applies, any loss from such activity for the taxable year shall be allowed only to the extent of the aggregate amount with respect to which the taxpayer is at risk (within the meaning of subsection (b)) for such activity at the close of the taxable year. Any loss from such activity not allowed under this section for the taxable year shall be treated as a deduction allocable to such activity in the first succeeding taxable year.

(b) Amounts Considered at Risk.—

(1) In general.—For purposes of this section, a taxpayer shall be considered at risk for an activity with respect to amounts including—

(A) the amount of money and the adjusted basis of other property contributed by the taxpayer to the activity, and

(B) amounts borrowed with respect to such activity (as determined under paragraph (2)).

(2) Borrowed amounts.—For purposes of this section, a taxpayer shall be considered at risk with respect to amounts borrowed for use in an activity to the extent that he—

(A) is personally liable for the repayment of such amounts, or

(B) has pledged property, other than property used in such activity, as security for such borrowed amount (to the extent of the net fair market value of the taxpayer's interest in such property).

47. (Cont'd.)

No property shall be taken into account as security if such property is directly or indirectly financed by indebtedness which is secured by property described in paragraph (1).

(3) Certain borrowed amounts excluded.—For purposes of paragraph (1)(B), amounts borrowed shall not be considered to be at risk with respect to an activity if such amounts are borrowed from any person who—

(A) has an interest (other than an interest as a creditor) in such activity, or

(B) has a relationship to the taxpayer specified within any one of the paragraphs of section 267(b).

(4) Exception.—Notwithstanding any other provision of this section, a taxpayer shall not be considered at risk with respect to amounts protected against loss through nonrecourse financing, guarantees, stop loss agreements, or other similar arrangements.

(5) Amounts at risk in subsequent years.—If in any taxable year the taxpayer has a loss from an activity to which this section applies, the amount with respect to which a taxpayer is considered to be at risk (within the meaning of subsection (b)) in subsequent taxable years with respect to that activity shall be reduced by that portion of the loss which (after the application of subsection (a)) is allowable as a deduction.

(c) Activities to Which Section Applies.—

(1) Types of activities.—This section applies to any taxpayer engaged in the activity of—

(A) holding, producing, or distributing motion picture films or video tapes,

(B) farming (as defined in section 464(e)),

(C) leasing any section 1245 property (as defined in section 1245(a)(3)), or

(D) exploring for, or exploiting, oil and gas resources as a trade or business or for the production of income.

(2) Separate activities.—For purposes of this section, a taxpayer's activity with respect to each—

(A) film or video tape,

47. (Cont'd.)

(B) section 1245 property which is leased or held for leasing,

(C) farm, or

(D) oil and gas property (as defined under section 614).

shall be treated as a separate activity. A partner's interest in a partnership or a shareholder's interest in an electing small business corporation shall be treated as a single activity to the extent that the partnership or an electing small business corporation is engaged in activities described in any subparagraph of this paragraph.

(d) Definition of Loss.—For purposes of this section, the term "loss" means the excess of the deductions allowable under this chapter for the taxable year (determined without regard to this section) and allocable to an activity to which this section applies over the income received or accrued by the taxpayer during the taxable year from such activity.

This section was adopted specifically to restrict tax shelter activity in which nonrecourse leveraging of investments gave individual investors tax losses in excess of their economic risk. S. Rept. No. 94-938, 94th Cong., 2d Sess. 47 (1976). In the context of facts such as those presented by this case, section 465 would apparently prevent petitioner Brountas from enjoying losses in excess of the amount of his contributions to Coral I. On the other hand, because petitioner CRC is a corporation, it would not be subject to the at-risk limitation provided by section 465. Cf. section 704(d), as amended by the Tax Reform Act of 1976, note 51a, infra.

In the Revenue Act of 1978, Pub. L. No. 95-600, 92 Stat. 2763, the at-risk rules were further broadened. For taxable years beginning after December 31, 1978, the at-risk rules apply to all activities other than real estate and equipment leasing by closely-held corporations. As currently in effect, section 465 provides:

SEC. 465. DEDUCTIONS LIMITED TO AMOUNT AT RISK.

(a) Limitation to Amount at Risk.—

(1) In General.—In the case of—

(A) an individual,

(B) an electing small business corporation (as defined in section 1371(b)), and

47. (Cont'd.)

(C) a corporation with respect to which the stock ownership requirement of paragraph (2) of section 542(a) (determined by reference to the rules contained in section 318 rather than under section 544) is met,

engaged in an activity to which this section applies, any loss from such activity for the taxable year shall be allowed only to the extent of the aggregate amount with respect to which the taxpayer is at risk (within the meaning of subsection (b)) for such activity at the close of the taxable year.

(2) Deduction in Succeeding Year.—Any loss from an activity to which this section applies not allowed under this section for the taxable year shall be treated as a deduction allocable to such activity in the first succeeding taxable year.

(b) Amounts Considered at Risk.—

(1) In General.—For purposes of this section, a taxpayer shall be considered at risk for an activity with respect to amounts including—

(A) the amount of money and the adjusted basis of other property contributed by the taxpayer to the activity, and

(B) amounts borrowed with respect to such activity (as determined under paragraph (2)).

(2) Borrowed Amounts.—For purposes of this section, a taxpayer shall be considered at risk with respect to amounts borrowed for use in an activity to the extent that he—

(A) is personally liable for the repayment of such amounts, or

(B) has pledged property, other than property used in such activity, as security for such borrowed amount (to the extent of the net fair market value of the taxpayer's interest in such property).

No property shall be taken into account as security if such property is directly or indirectly financed by indebtedness which is secured by property described in paragraph (1).

47. (Cont'd.)

(3) Certain Borrowed Amounts Excluded.—For purposes of paragraph (1)(B), amounts borrowed shall not be considered to be at risk with respect to an activity if such amounts are borrowed from any person who—

(A) has an interest (other than an interest as a creditor) in such activity, or

(B) has a relationship to the taxpayer specified within any one of the paragraphs of section 267(b).

(4) Exception.—Notwithstanding any other provision of this section, a taxpayer shall not be considered at risk with respect to amounts protected against loss through nonrecourse financing, guarantees, stop loss agreements, or other similar arrangements.

(5) Amounts at Risk in Subsequent Years.—If in any taxable year the taxpayer has a loss from an activity to which this section applies, the amount with respect to which a taxpayer is considered to be at risk (within the meaning of subsection (b)) in subsequent taxable years with respect to that activity shall be reduced by that portion of the loss which (after the application of subsection (a)) is allowable as a deduction.

(c) Activities to Which Section Applies.—

(1) Types of Activities.—This section applies to any taxpayer engaged in the activity of—

(A) holding, producing, or distributing motion picture films or video tapes,

(B) farming (as defined in section 464(e)),

(C) leasing any section 1245 property (as defined in section 1245(a)(3)),

(D) exploring for, or exploiting, oil and gas resources, or

(E) exploring for, or exploiting, geothermal deposits (as defined in section 613(e)(3))

as a trade or business or for the production of income.

(2) Separate Activities.—For purposes of this section, a taxpayer's activity with respect to each—

(A) film or video tape,

47. (Cont'd.)

(B) section 1245 property which is leased or held for leasing,

(C) farm,

(D) oil and gas property (as defined under section 614), or

(E) geothermal property (as defined under section 614)

shall be treated as a separate activity. A partner's interest in a partnership or a shareholder's interest in an electing small business corporation shall be treated as a single activity to the extent that the partnership or an electing small business corporation is engaged in activities described in any subparagraph of this paragraph.

(3) Extension to Other Activities.—

(A) In General.—In the case of taxable years beginning after December 31, 1978, this section also applies to each activity—

(i) engaged in by the taxpayer in carrying on a trade or business or for the production of income, and

(ii) which is not described in paragraph (1).

(B) Aggregation of Activities Where Taxpayer Actively Participates in Management of Trade or Business.—Except as provided in subparagraph (C), for purposes of this section, activities described in subparagraph (A) which constitute a trade or business shall be treated as one activity if—

(i) the taxpayer actively participates in the management of such trade or business, or

(ii) such trade or business is carried on by a partnership or electing small business corporation (as defined in section 1371(b)) and 65 percent or more of the losses for the taxable year is allocable to persons who actively participate in the management of the trade or business.

(C) Aggregation or Separation of Activities Under Regulations.—The Secretary shall prescribe regulations under which activities described in sub-

47. (Cont'd.)

paragraph (A) shall be aggregated or treated as separate activities.

(D) Exclusions.—

(i) Real Property.—In the case of activities described in subparagraph (A), the holding of real property (other than mineral property) shall be treated as a separate activity, and subsection (a) shall not apply to losses from such activity. For purposes of the preceding sentence, personal property and services which are incidental to making real property available as living accommodations shall be treated as part of the activity of holding such real property.

(ii) Equipment Leasing by Closely-Held Corporations.—

(I) In the case of a corporation described in subsection (a)(1)(C) actively engaged in leasing equipment which is section 1245 property, the activity of leasing such equipment shall be treated, for purposes of subsection (a), as a separate activity and subsection (a) shall not apply to losses from such activity.

(II) A corporation described in subsection (a)(1)(C) shall not be considered to be actively engaged in leasing such equipment unless 50 percent or more of the gross receipts of the corporation for the taxable year are attributable, under regulations prescribed by the Secretary, to leasing and selling such equipment.

(III) For purposes of this paragraph, the leasing of master sound recordings, and other similar contractual arrangements with respect to tangible or intangible assets associated with literary, artistic, or musical properties shall not be treated as leasing equipment which is section 1245 property.

47. (Cont'd.)

(IV) In the case of a controlled group of corporations (within the meaning of section 1563(a)), this paragraph shall be applied by treating the controlled group as a single corporation.

(E) Application of Subsection (b)(3).—In the case of an activity described in subparagraph (A), subsection (b)(3) shall apply only to the extent provided in regulations prescribed by the Secretary.

(d) Definition of Loss.—For purposes of this section, the term "loss" means the excess of the deductions allowable under this chapter for the taxable year (determined without regard to the first sentence of subsection (a)) and allocable to an activity to which this section applies over the income received or accrued by the taxpayer during the taxable year from such activity.

(e) Recapture of Losses Where Amount at Risk is Less Than Zero.—

(1) In General.—If zero exceeds the amount for which the taxpayer is at risk in any activity at the close of any taxable year—

(A) the taxpayer shall include in his gross income for such taxable year (as income from such activity) an amount equal to such excess, and

(B) an amount equal to the amount so included in gross income shall be treated as a deduction allocable to such activity for the first succeeding taxable year.

(2) Limitation.—The excess referred to in paragraph (1) shall not exceed—

(A) the aggregate amount of the reductions required by subsection (b)(5) with respect to the activity for all prior taxable years beginning after December 31, 1978, reduced by

(B) the amounts previously included in gross income with respect to such activity under this subsection.

total amount of the drilling contract prices for the Lease Purchase and Turnkey Drilling Agreements entered into with the various operators. Respondent allowed IDCs represented by cash invested but determined that no deductions were allowable with respect to the note portion of the drilling contract price. Specifically, respondent determined that petitioners are entitled to tangible drilling and development cost deductions only to the extent of the cash portion of the drilling contract price because (a) the notes were shams, (b) the nonrecourse notes did not provide basis in the investors' partnership interests, or (c) the partnerships only incurred IDCs to the extent of the cash spent. Petitioners, on the other hand, contend that they are entitled to IDC deductions with respect to the note portion of the drilling contract prices because (a) the nonrecourse note represents a bona fide, albeit contingent, obligation incurred as part of the consideration given to the operator, (b) the face amount of the note is added to the investors' bases in their interests in the partnership as either a loan or a production payment (treated as a loan), and (c) the package of consideration given to the operators (*i.e.*, cash, note and completion option) was worth at least the face value of the no-out turnkey drilling contract. For reasons expressed hereinafter, we agree with petitioners on this issue.

A. Sham.

Respondent's primary contention in this case is that the note portion of the Lease Purchase and Turnkey Drilling Agreements was a sham. Respondent summed up his position succinctly on brief: "The gravamen of respondent's position is that petitioners' program was a tax gimmick and a fraud." Respondent contends that the true, or economic, deal was limited to the cash portion of the price; that the contingent "note" portion was a mat-

ter of no economic import cynically added on at CRC's behest to an otherwise entirely fair arrangement, contrary to sound economic practice and solely to swell the nominal price in order to generate a fictitious, large, front-end shelter in excess of cash investment. Were this characterization correct, we may assume for present purposes that we could ignore the notes and uphold respondent on this issue. However, this question is a factual one, and we have rejected respondent's contention in our Findings. Nevertheless, because of the importance of this factual question, as well as the length and complexity of the evidentiary record, we believe that discussion of our Findings is necessary.

1. Economic Reality of the Notes. It is well settled that the economic substance of these transactions, rather than their form, governs for tax purposes. *Gregory v. Helvering,* 293 U. S. 465 (1935). In *Higgins v. Smith,* 308 U.S. 473, 477 (1940), the Supreme Court elaborated on this principle:

> * * * the Government may not be required to acquiesce in the taxpayer's election of that form for doing business which is most advantageous to him. The Government may look at actualities and upon determination that the form employed for doing business or carrying out the challenged tax event is unreal or a sham may sustain or disregard the effect of the fiction as best serves the purposes of the tax statute.

However, in *Frank Lyon Co. v. United States,* 435 U.S. 561, 583-584 (1978), the Supreme Court noted that where

> * * * there is a genuine multiple-party transaction with economic substance which is compelled or en-

couraged by business or regulatory realities, is imbued with tax-independent considerations, and is not shaped solely by tax-avoidance features that have meaningless labels attached, the Government should honor the allocation of rights and duties effectuated by the parties.

In this case, the principal dispute involves the nonrecourse note. The operators and CRC negotiated agreed-upon contract prices for mineral leases and for a no-out turnkey drilling contract to be undertaken by the operator. The operator then lent 60 percent of this total price ("the note portion") to CRC and the limited partnerships ("Investors"). For this loan, the operator received a nonrecourse note payable as a practical matter only from production. The Investors, in turn, used this note portion plus the cash portion (which was derived from the contributions of the limited partners and was 40 percent of the total contract price) to "pay" the operator the total agreed price for the leases and the no-out turnkey drilling contract (hereinafter "the total contract price").

Respondent says that the note portion was a sham introduced "to create a tax deduction in excess of the amount known to be allowable." His position has changed through the course of this case. At trial respondent stated that the crux of his case was that the total contract prices agreed to by the operators and CRC were not reasonable. In his opening brief respondent maintained this position and argued, further, that the operators did not in reality finance 60 percent of the cost of the test wells. In the reply brief, however, respondent retreated from his original argument and asserted that it is not relevant whether the total contract price negotiated by the operators was fair and reasonable; rather, respondent now contends that the parties *negotiated* for only the

cash portion of the total contract price. Respondent now argues that the note portion was an unbargained-for addition to the terms of an otherwise reasonable contract "tacked on" at CRC's insistence only for its own and its partners' tax benefit. Accordingly, respondent contends that the notes lack economic substance. To test the merits of respondent's contention, it is necessary to analyze the business dynamics of the CRC-operators transactions. Our analysis supports petitioner rather than respondent.

Preliminarily, we have found, as respondent argues, that the operators did not "finance" 60 percent of the cost of the no-out turnkey contracts. We found that the operators borrowed the note portion of the total contract price from a bank, "loaned" this money to CRC and, when the total contract price was received, used 60 percent of this to repay the bank. Such a "loan" must be disregarded for tax purposes, and petitioners readily concede as much. In fact, petitioners contend that the "loan" format was instituted solely on the advice of CRC's accountants, who wanted to create an audit trail. The loan may be ignored. The operators in substance accepted 40 percent cash, a cross-collateralized nonrecourse note for 60 percent, and a completion option, all in exchange for their leasehold interest and their no-out turnkey drilling obligation.

We have found, contrary to respondent's contention, that the nonrecourse notes which the Investors gave to the operators had economic significance and were a bona fide and bargained for part of these transactions. These transactions were integrated wholes. The specific bundle of rights which each operator received was arrived at through arm's length negotiations between the operators and CRC, and the terms of the resulting contractual agreements were within a reasonable range of commercial practice.

Specifically, operators who had prospects which they wished to test approached CRC; the operators had heard of CRC and its drilling program by word-of-mouth within the oil and gas industry. The operators presented to Bill Floyd, CRC's chief geologist, prospect data sheets on which the operators described their package of properties, the hoped-for discovery of oil and gas, their lease price, their no-out turnkey drilling contract price, and their total price for a lease and a no-out turnkey drilling contract. The operators were aware, when they submitted these prospect data sheets, that they would receive only a portion of their total contract price (usually 40 percent) in cash, and 60 percent of the price would be represented by a cross-collateralized nonrecourse note. They were also aware of the completion option which they would receive if a contract were entered into.

Floyd considered the geological merits of the prospects, and on geological grounds he rejected 90 to 95 percent of the prospects offered to him. If he approved a prospect, he and the operator then negotiated terms. Floyd was a hard bargainer, who vigorously pursued CRC's interests. All price negotiations dealt with the total lease purchase price and the total drilling contract price; Floyd never negotiated the cash portion and then added to it the note portion.

Floyd and the operators negotiated prices for the leases and the no-out turnkey drilling contract which were objectively fair and reasonable at least considering the fact that part of the price would be represented by a highly contingent obligation.[48] Because of its bargaining

48. In order to decide the sham issue, we did not need to go farther and decide whether, as petitioners contend and numerous witnesses testified, the 150 percent markup for the no-out turnkey obligation would have been commercially fair if represented by cash rather than a contingent obligation. Respondent has not

position, CRC was able to require the operators to accept only 40 percent (usually) of this total contract price in cash; the remainder was paid with a cross-collateralized non-recourse note secured only by production, and with the completion option, which enabled the operator to recapture a percentage of the production from a successful lease if the operator paid the completion costs and repaid the lease costs.

None of the operators would have accepted these transactions with CRC even for a cash payment of the total contract price without the completion option. They wanted an interest in the reserves, this being the principal business interest of an operator as distinguished from a lease broker. The completion option required the operators to pay the costs of completion after a well drilled to casing point showed promise of being a producer, in order to recapture an interest in the lease.

CRC's format met the goals of both the operators and the Investors. The Investors received a no-out turnkey drilling obligation, which, with the completion option, effectively guaranteed that all their wells would be drilled, and good ones completed, at no further cost to them despite any drilling difficulties which could arise. Because

48. (Cont'd.)

questioned in this case, and we therefore need not consider, the allocation of the total contract price between the lease purchase price and the drilling contract price. Compare *Bernuth v. Commissioner*, 57 T.C. 225 (1971), affd. 470 F.2d 710 (2d Cir. 1972). Testimony that the drilling contract prices were fair and reasonable without regard to the contingent nature of the portion thereof represented by the notes was given by numerous independent petroleum engineers. We found their testimony forthright, and generally credible but essentially conclusory as there were no comparables on which to base such conclusion. There was no credible contrary testimony on this point although one witness for respondent said the drilling prices were excessive based on contract drilling average prices and not no-out turnkeys.

of the no-out obligation, the operators (rightfully) demanded and received a much larger price than would be fair for an obligation which let them out if high pressure, or low pressure, etc. were encountered. However, the operators received in cash only an amount sufficient to cover their anticipated no-problem costs and profit; the remainder of the price for their no-out turnkey drilling contracts was represented by nonrecourse notes. For the Investors this format was advantageous since it required less cash up front; on the other hand, the operators looked for more for their work due to the extra risks they undertook. However, the operators could collect on the note only if hydrocarbons were found, although the chances of payment were substantially greater in that the notes were cross-collateralized, meaning that one note could be paid from the production from a group of dispersed wells (usually three). This contingent nature of the operators' compensation was of considerable benefit to the Investors; not only did they have to contribute less cash, but in addition the operators' self-interest led the operators to offer only their best prospects to CRC.[49] Finally, the completion option provided the operators with the interest in production which they demanded. Yet even this completion option was beneficial to the Investors, since the operators were required to pay all completion costs and repay the lease cost to the Investors. The entire arrangement was well within a reasonable range of commercial practice and clearly had economic reality.

49. If a portion of the operator's compensation were contingent upon production, the operator had every inducement to insure such production. The overall production success of the 1972 drilling program supports this inference. Without real faith in its prospects, the operator would have been unwilling to expose itself to the no-out drilling obligation for a price (40 percent) which provided scant, if any, profit to it if *no* problems were encountered.

The economic reality of CRC's program is further supported by a comparison to the so-called "third for a quarter" deal, which was a relatively standard arrangement among oil and gas partners in the oilfields. Respondent contends that a comparison with the third for a quarter transaction reveals the sham nature of CRC's transaction, particularly the nonrecourse note, but we conclude that such a comparison leads to the opposite conclusion. In a third for a quarter arrangement, an operator transfers his leasehold interest to the investors in return for the investors' agreement to pay the entire cost of drilling and completing a test well.[49] The operator retains a twenty-five percent interest, so that if the well is successful, the operator is entitled to 25 percent of production and the investors receive the remaining 75 percent.

By comparison, under CRC's program the Investors paid through casing point in cash only an amount expected to cover the operator's expected no-problem costs, which might not turn out to be the total costs.[50] If difficulties were encountered (as they were in the Boyken Church prospect, where the well had to be drilled three times and then was dry), the operator had to pay all the extra costs. The operator was paid for his assumption of this risk by a much higher drilling contract price, although 60 percent of that price would be paid only if at least one of the wells in a package were sufficiently commercially successful to cover the price. Under a third for a quarter arrangement, the operator had to pay *none* of the costs through casing point. Moreover, if at casing point the operator decided to complete a well, under CRC's program the operator would be motivated by the completion option to pay all the completion costs (and reimburse the cash portion of the lease purchase price plus tangibles to

50. The Investors also paid in cash a portion of the lease purchase price.

the Investors). In return, the operator received a 40 percent interest in the well, which was reduced, in some instances, after pay out to 26⅔ percent. In contrast, under a third for a quarter arrangement the operator received a 25 percent interest for payment of *none* of the costs through completion.

A comparison of these two formats reveals, we conclude, that without the nonrecourse notes CRC's format would be extremely disadvantageous to an operator. Without the note, under CRC's program the operator would have received only the cash portion of the no-out turnkey drilling contract which was his expected no-problem cost of drilling to casing point plus a profit element (and the operator took all attendant risks), and the operator would have to pay all completion costs if the well were successful. In return, the operator would have received an interest in production which, after pay out, was not significantly greater than the interest he would receive under a third for a quarter arrangement in which the operator pays no costs. In essence, the operator would receive about the same interest it would receive in a third for a quarter arrangement, but the operator would have assumed the drilling risk and paid all completion costs. However, under CRC's format an operator also received the nonrecourse note, which entitled him to a share of production, if any. Although the value received through the note cannot be strictly correlated to either the risks undertaken by the operator or the completion costs incurred, the note was clearly an economically significant additional piece in the package which compensated the operator for the obligations which the operator undertook. In fact, respondent's principal witness, Scoggins, testified that there was not sufficient profit for an operator to justify the CRC transaction without the note. Even with the note, in light of the fact that the operator incurred all

risks of drilling, paid all completion costs, and recovered on the note only if oil or gas were found, we believe that CRC's program was less advantageous to an operator than a third for a quarter arrangement, unless the possibility of finding minerals was very high.

The reason CRC was able to negotiate these terms with operators—terms relatively disadvantageous to the operators—was CRC's bargaining position. In the years in question, CRC was one of the few sources of available capital for operators who wanted to drill wells. Because of its position as the moneyed party, CRC could require the operators to accept somewhat onerous conditions including (1) the operators received 60 percent of the contract price for the no-out turnkey drilling obligation only in the form of a nonrecourse note, (2) the operators received 60 percent of the lease purchase prices through a nonrecourse note, and (3) the operators had to pay all completion costs. The net effect of these conditions was that CRC did not have to use its front-end cash to pay the full price for the leases, the full no-out turnkey contract price or the costs of completion. By imposing these terms, CRC was able to use its funds to invest in more wells.

In reaching our conclusion that CRC's transactions (including the nonrecourse notes) had economic substance, we have viewed these transactions as a whole. These transactions were carefully structured so that the entire package of compensation which flowed from the Investors to the operators was within a reasonable range of commercial practice in light of the obligations which the operators assumed. We conclude that one part of this package—the nonrecourse notes—cannot properly be picked out of these transactions and be labeled a sham, as that piece provided a necessary part of the consideration which the operators received. To be sure, CRC structured those arrangements to provide tax shelter, and

intended that the nonrecourse note would yield tax benefits to the investors in the limited partnerships, but there were sound economic reasons for the use of such obligations in these transactions. As we stated in *McLane v. Commissioner*, 46 T.C. 140, 145 (1966), affd. per curiam 377 F. 2d 557 (9th Cir. 1967), cert. denied, 389 U.S. 1038 (1968):

> The building may not be constructed entirely from the tax advantage, but, if the foundation and bricks have economic substance, the economic or financial inducement of the tax advantage can provide the mortar.

2. *Respondent's Factual Contentions.* In support of his determination that the nonrecourse notes were shams, respondent relies on the following: (a) that some of the operators hoped not only to cover the no-problem drilling costs but also to be compensated even for the risks of the no-out turnkey drilling contract with the cash received, (b) the testimony of Scoggins, a discharged employee of GeoDynamics, that the notes were shams added to the contracts for tax reasons, (c) the facts of the Elpac transactions, and (d) the facts of the Duquesne-Kiowa-TNT transaction. We are unpersuaded.

First, respondent points out that certain operators testified that they took the risk into consideration in arriving at the cash portion of the drilling price. Thus, respondent concludes, any amount in excess of the cash portion (*i.e.*, the notes) had no economic purpose. Respondent's conclusion, however, is undermined by the weight of the evidence. In the first place, the same operators who testified that they hoped to be compensated for their risks as well as no-problem costs with the cash received all also testified that the drilling contract prices (cash and note portion) they negotiated with

Floyd were, in all cases, fair and reasonable. And respondent has apparently abandoned his original determination to the contrary. Second, independent petroleum engineers (who were unaware that a portion of the drilling contract price would be paid with a note) certified in each case that the prices were fair and reasonable in light of the risks undertaken. Third, respondent introduced no credible evidence that the price was excessive. Fourth, the magnitude of the risks the operators took when they accepted a no-out turnkey drilling contract was illustrated in the Boyken Church prospect, for which Patrick Petroleum Company had to spend several times the cash received in order to drill a dry hole. The fact that the operators *hoped* to meet all costs with the cash received and *considered* the risks does not mean the cash price alone sufficed as adequate compensation for the risks. It does not negate the fact that the drilling contract prices, in light of the risks undertaken and the contingent nature of the note portion, were fair and reasonable. Finally, we do not view the nonrecourse notes only in relation to the risks which the operators accepted in the no-out turnkey contracts. Rather, as we have previously stated, the notes were an integral and necessary part of the consideration which flowed from the Investors to the operators. Accordingly, as long as the total consideration received was fair and reasonable and arrived at through arm's length negotiations, we do not find determinative that some of the operators hoped to cover not only their drilling costs but also possible unforeseen costs under the no-out turnkey contract with the cash received.

Respondent's second factual support for his sham argument is based on the testimony of Charles Scoggins. Along with Dauber, Scoggins was a co-founder of GeoDynamics in 1969, and was its chief geological officer in 1970. Scoggins was discharged by GeoDynamics in early

1971 for alleged incompetency and dishonesty, although in 1972 he contracted with CRC as an operator. His transaction with CRC in 1972 followed the standard format.

Scoggins testified in effect that the nonrecourse notes were shams added to the transactions solely for tax purposes. Scoggins testified that he objected to this format, and he claimed that he resigned from GeoDynamics because he was worried about his own legal liability.[51] Scoggins also stated that when he contracted with CRC in 1972, he took the fair and reasonable price for the leases and for drilling the wells (the cash portion) and multiplied this amount by 2½ to reach the total contract price. The amount in excess of the fair and reasonable price was the note portion of the total contract price. Accordingly, Scoggins believed that the total contract prices were not fair and reasonable.

If we believed Scoggins' testimony, it would be strong evidence that the nonrecourse notes were, as respondent contends, shams added to these transactions solely for tax purposes. However, we did not find Scoggins to be a candid or credible witness. In the first place, on the witness stand he was evasive and uncooperative. Secondly, petitioners' counsel brought forth numerous instances in which Scoggins' prior sworn testimony was inconsistent with his testimony before us.[52] These inconsistencies undermined his credibility.

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51. We found that Scoggins was discharged by Dauber.

52. For example, Scoggins testified before us that the loan portions of the contract price were merely added to a fair and reasonable price for a turnkey contract. However, in prior testimony, Scoggins stated that as an operator "[he] would never have made the trade without the loan. * * * There wasn't enough profit in it without the loan."

There are many other examples of such contradictory testimony in the record. Scoggins testified in response to a question by the Court that a no-out provision in a turnkey contract made no

Moreover, Scoggins' testimony was in direct contradiction to the credible testimony of numerous operators and petroleum engineers to the effect that both the lease purchase and drilling contract prices were fair and reasonable and reached in arm's length negotiations. Scoggins, on the other hand, testified that the operators contracted with CRC with "tongue in check and a wink of the eye." If we accept Scoggins' testimony, we must then conclude that these operators and petroleum engineers were not truthful in their testimony. However, we found these operators and engineers credible witnesses. For example, when Scoggins contracted with CRC in 1972, he was required to obtain an appraisal from an independent petroleum engineer that the drilling contract price was fair and reasonable. Scoggins contacted James Blackmon, who wrote such an opinion. At trial Blackmon reaffirmed his opinion under oath, and we found Blackmon, unlike Scoggins, to be a candid and credible witness. Nonetheless, Scoggins testified that he and Blackmon "laughed about" the opinion letter and, further, that Blackmon was "lying" if he testified that the drilling contract price was fair and reasonable. In light of Blackmon's forthright demeanor and otherwise uncontradicted testimony, and Scoggins' contradictions of his own prior sworn testimony, Scoggins'

52. (Cont'd.)

difference or, at most, would add 15 to 20 percent to the cost of a contract. However, in sworn testimony before the Securities and Exchange Commission, Scoggins stated that the no-out provisions employed by CRC made the contracts "much more risky" from the operator's point of view. Scoggins also testified before us that he had consulted with Sheldon Cohen, then Commissioner of Internal Revenue, as to his (Scoggins') possible liability due to his participation in the CRC drilling program. However, in prior testimony Scoggins stated under oath that he had not consulted with Mr. Cohen. Finally, Scoggins' prior testimony contradicts the explanation he gave before us as to why he "resigned" from Geo-Dynamics.

assertion that Blackmon was lying is part of the basis for our conclusion that Scoggins' testimony must be disregarded.

Respondent's third major factual contention is that the Elpac transactions indicate that the notes were shams. In the Elpac transactions, operators which did not have net operating loss carryovers but which wished to deal with CRC brought a third party—Elpac—into the transaction, primarily to absorb the income tax consequences of the notes.[53] Elpac had a large net operating loss carryover, which it used in these transactions. In these transactions, Elpac would contract with CRC, receiving the total contract price (cash and note portions) plus the completion option for its (Elpac's) assumption of the obligations under the Lease Purchase and Turnkey Drilling Agreement. Elpac would then assign the cash portion of the total contract price plus the completion option to an operator.[54] In return, the operator would promise to drill the test wells. Elpac agreed to pay 50 percent of any cost overruns on the drilling to the operator. Moreover, the obligation of the operator to Elpac was not as broad as Elpac's obligation to CRC under the no-out turnkey drilling contract. From CRC's point of view, the Elpac transactions were similar to other transactions since CRC received the leases and a no-out turnkey drilling obligation for a fair and reasonable price.

Nonetheless, respondent contends that the Elpac transactions prove that the notes lack economic substance.

53. The notes were reported at face value as income to the operator in the year received, but the notes provided no cash immediately to pay the tax on this income. Accordingly, only operators with net operating loss carryovers could "afford" the notes.

54. Two out of the three operators with which Elpac contracted also received from Elpac a production payment, usually equivalent to 15 percent of the note portion of the total contract price.

Specifically, respondent argues that these transactions show that the operators were willing to undertake to drill the test wells for just the cash portion of the drilling contract price and the completion option. As a corollary, respondent asserts that the fact that only net operating loss carryover companies were willing to contract under this format establishes the lack of economic substance in CRC's format.

We are unpersuaded by respondent's arguments. In the Elpac-McMoRan transactions McMoRan agreed to drill the test wells for only the cash portion of the drilling contract price, Elpac's risk-sharing contract and the completion option. Similarly, in the Elpac-Gibraltar and Elpac-Sinclair transactions, the operators agreed to drill the wells for the cash portion, the completion option, the risk-sharing contract, and a production payment equal to 15 percent of the note which Elpac had received from the Investors. However, we do not conclude from these facts that the notes were shams. Rather, we conclude that the operators' actions are understandable in light of (1) the lesser obligation they undertook in their drilling contracts with Elpac and (2) the context in which the Elpac transactions arose. Combined, these factors illustrate the economic substance of the notes and their role in these transactions.

In the first place, Elpac's obligation to the Investors was the no-out turnkey drilling obligation which all other operators which contracted with CRC assumed. This no-out obligation was absolute and binding—Elpac had to deliver the test wells and logs to the Investors no matter what the cost and no matter what drilling problems were encountered. Elpac promised to hold the Investors harmless from any and all claims, to furnish all logs necessary to evaluate the test wells, and to conduct the drilling at its "sole cost, risk and expense." Included in Elpac's

liability were all environmental costs, which could be great, as well as all drilling costs of any nature. Moreover, Elpac was liable to the Investors regardless of whether the operators performed their drilling obligations. In contrast, in the Elpac transactions the operators' obligations to Elpac were somewhat less broad in scope. Specifically, the operators merely promised to perform the drilling, to furnish Elpac with one induction electric log, and to pay the costs thereof. The practical significance of this distinction is not determinable from the record.

Second, and more important, in addition to assuming broader obligations than the operators, Elpac also agreed to share any cost overruns with them. In other words, to the extent that the operators' drilling costs exceeded the cash portion of the total contract price, Elpac agreed to pay 50 percent of such excess. By this agreement, Elpac further assumed directly from the operators a portion of the risks attendant upon a no-out turnkey drilling contract.

In combination, Elpac's broader contractual obligation and its assumption of 50 percent of the overrun risks of the no-out contract explain why one of the three operators would agree to drill the wells in the Elpac transactions without receipt of part of the note.[55] The operators assumed less risk in the Elpac transactions; part of their risk was assumed by Elpac. In return for the risks assumed, which were contingent in nature, Elpac received contingent compensation.[56] On the other hand, because

55. However, two of the three operators—Gibraltar and Sinclair—were unwilling to drill without any portion of the note. Rather, they negotiated with Elpac and received a production payment equivalent to 15 percent of the note portion of the total contract price.

56. The risks which Elpac undertook were "contingent" in that Elpac would not be subject to liability unless the operators failed to drill or unless costs exceeded the cash portion of the total contract price. On the other hand, the compensation Elpac received—

the operators did not assume all these risks, they received less than had they dealt with CRC directly. CRC, however, paid the same amount in order to receive the same drilling obligation.

Additionally, the Elpac transactions can be understood only in the context in which they arose. For example, with respect to McMoRan, in 1970 McMoRan had a very successful relationship with CRC in that McMoRan discovered considerable oil and gas reserves, and McMoRan desired to continue this relationship in 1971. However, two significant changes occurred in 1971: first, McMoRan no longer had a net operating loss carryover; second, CRC changed the format of its transactions so that the notes could not be converted into a working interest. McMoRan concluded, on the basis of these changes, that it did not wish to accept the notes.[57] Accordingly, in order to be able to continue its successful relationship with CRC in a format which was acceptable to CRC (*i.e.*, a format in which a price for the drilling contract was represented partly by cash and partly by a note), McMoRan introduced Elpac into these transactions.[58] McMoRan brought

56. (Cont'd.)

the notes—were "contingent" in that they were basically worthless unless hydrocarbons in commercial quantities were found in the well or another well with respect to which they were cross-collateralized.

57. McMoRan evidently decided that the immediate tax consequences of receipt of the notes (*i.e.*, payment of corporate income tax on the face amount of the notes) was not justified by the eventual return several years later if the test wells were successful. B. M. Rankin, who was president of McMoRan, indicated as much when he stated that McMoRan believed the notes were "uneconomical" for it.

58. Elpac participated in these transactions for its own benefit, not for the benefit of McMoRan or CRC. Elpac was willing to employ its net operating loss carryover because it hoped to receive a profit from the notes.

Elpac into the transaction by compensating Elpac with the nonrecourse notes; in return, Elpac assumed much of the excess risk which McMoRan had carried when McMoRan contracted directly with CRC. McMoRan decided that it was willing to forego the benefits which the notes represented in return for less risk and fewer adverse tax consequences. Such an economic decision on the part of McMoRan does not deprive the note portion of these transactions of economic substance. Rather, the Elpac transactions illustrate that the notes had substance within these transactions—the notes were part of the compensation for the risks which the operators undertook in the no-out turnkey drilling contract. When the operators took less risk, they were willing to give all or a portion of the note to the party which bore the risk. Such *quid pro quos* are virtually the definition of economic substance.

We are similarly unpersuaded by respondent's corollary argument that the notes were shams since only operators with net operating loss carryover could afford to participate in the CRC transactions. We considered a similar argument in *Brown v. Commissioner*, 37 T.C. 461 (1961), affd. 325 F.2d 313 (9th Cir. 1963), affd. on another issue, 380 U.S. 563 (1965), and rejected it. In *Brown* the taxpayer's transaction made economic sense only if the other party in the transaction were a tax-exempt organization; respondent argued that the transaction was therefore a sham. We rejected respondent's contention because (1) the exempt organization was a long-standing, independent institution, (2) the terms of the contract were reached through arm's length negotiations, and (3) the price agreed upon was within a reasonable range. 37 T.C. at 486-487. The facts of this case are analogous in that only operators with net operating loss carryovers wanted to participate directly in these transactions with CRC. But since all the operators were

independent of CRC, all contracts were reached through arm's length negotiations, and the terms agreed upon were within a reasonable range of commercial practice, the fact that only operators with net operating loss carryovers would participate does not make these transactions shams. Rather, these were bona fide transactions in which tax considerations played a role.

Finally, respondent contends that the Duquesne-Kiowa-TNT transaction establishes that the nonrecourse notes were shams introduced only for tax purposes. The Duquesne-Kiowa-TNT transaction was similar to the Elpac transactions except in two significant respects. First, this transaction contained an extra level. Taylor was the president of TNT, a thinly-capitalized operator which had a prospect (the Singer prospect) which TNT wished to develop, but TNT lacked sufficient funds. Taylor agreed with Kiowa, another operator, that TNT would test the prospect for $75,000 plus a 1/16 interest. The proposed contract was not a no-out turnkey contract but had the usual Gulf Coast "outs." Taylor believed that the price was low, but he accepted it because he had no other source of cash, the leases for the Singer prospect were about to terminate, and this prospect, if successful, would be a starting point for his reputation as an oil and gas operator. Kiowa, in turn, sought financing from CRC. Kiowa and CRC agreed to a lease purchase price of $10,000 and no-out turnkey drilling contract price of approximately $205,000, of which the cash portion was $85,650. Jerry Freel of Kiowa then returned to Taylor and told Taylor that TNT would have to test the Singer prospect on a no-log, no-pay [59] basis for the agreed-upon

59. A no-log, no-pay turnkey drilling contract is less onerous than a no-cut turnkey drilling contract. In the latter the operator *must* reach casing point and log the well, regardless of cost, while in the former if the operator encounters obstacles it can simply walk away from the prospect and not get paid.

price. At first Taylor demurred, but eventually he agreed to the change because due to TNT's financial condition he believed he had little to lose. Taylor believed that a fair and reasonable price for such a no-log, no-pay turnkey drilling contract was approximately $225,000.

The second significant variation between this transaction and the Elpac transaction concerns the "lender." Freel arranged with Duquesne, which was a net operating loss carryover company, to accept the nonrecourse note.[60] In contrast to the Elpac transactions, however, here Kiowa expressly assumed all of Duquesne's drilling obligations under Duquesne's contract with CRC. There was, however, no novation. Duquesne remained residually liable. Therefore, in this transaction Duquesne received the nonrecourse notes but fully laid off its drilling obligation to Kiowa, Kiowa received the completion option plus $85,650 and was legally bound to Duquesne under a no-out turnkey drilling obligation, and TNT was obligated under a no-log, no-pay contract with Kiowa to drill the Singer prospect for $75,000 plus a 1/16 interest in the well.

Respondent contends that the Duquesne-Kiowa-TNT transaction establishes that the nonrecourse notes were shams. Respondent's argument, primarily, is that Kiowa proved the lack of substance of the notes by its willingness to assume the no-out turnkey drilling obligation without the receipt of the notes, while Duquesne received the notes but undertook no material risks.[61] Therefore, re-

60. We do not know why Freel (a) contracted with CRC, (b) agreed to a no-out turnkey price in excess of the amount he had agreed to with Taylor, or (c) contacted Duquesne to take the note. Respondent subpoenaed Freel as a witness, and he appeared at the trial but respondent did not call him.

61. This distinguishes this transaction from the Elpac transactions in which Elpac assumed several risks: (1) Elpac's obligation to CRC was broader than the operators' obligations to Elpac

spondent contends that the notes were not a necessary part of the transaction but were added solely for tax reasons.

The fundamental question here is: why was Kiowa willing to assume the no-out turnkey drilling obligation without receiving the nonrecourse notes? Also, did Duquesne receive the nonrecourse notes without assuming any risk? After careful consideration of all the facts and circumstances of the Duquesne-Kiowa-TNT transaction, we conclude that in reality Duquesne did incur risks for which it received the notes, while Kiowa assumed less risks than an operator normally assumed in a transaction with CRC.

Duquesne incurred real risks because the two other companies which agreed to drill the test well on the Singer prospect—TNT and Kiowa—were both very weak financially. Neither TNT nor Kiowa had the financial resources necessary to redrill the Singer well repeatedly if troubles were encountered; on the other hand, Duquesne had such resources. Indeed, Duquesne's internal memorandum with respect to this transaction noted that "Duquesne would be in the middle on the legal responsibility to provide the turnkey job and if something happened to the third party—could end up holding the bag." Duquesne incurred this risk notwithstanding Kiowa's assumption of Duquesne's obligations under the CRC contract, since CRC could proceed against Duquesne if the Singer well were not drilled according to contract specifications. In light of the financial weakness of Kiowa, Duquesne in reality had much of the risk of the no-out contract.

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61. (Cont'd.)

and (2) Elpac was obligated to share cost overruns with the operators. Here, in contrast, Duquesne's obligation was expressly assumed by Kiowa.

With respect to Kiowa, we conclude that the presence of TNT in this transaction significantly affected Kiowa's position. TNT promised to drill the Singer prospect on a no-log, no-pay basis for slightly less than the cash portion of the total contract price. Accordingly, the risks which Kiowa undertook by assuming the no-out turnkey contract from Duquesne were, in reality, shared with TNT. Additionally, because TNT's contract was no-log, no-pay, which meant that Kiowa did not have to pay TNT if TNT failed to reach casing point and test the well, in a substantive economic sense Kiowa had double the cash for drilling the Singer well. In other words, TNT agreed to drill the Singer prospect for approximately $75,000, which was less cash than Kiowa received from CRC. If TNT were successful, Kiowa would be able to pay TNT from the cash received and still make a profit. On the other hand, if TNT failed to reach casing point, Kiowa did not have to pay TNT. Kiowa could then use the cash received from CRC to make another drilling attempt. Kiowa's contract with TNT thus greatly reduced Kiowa's risk.

We conclude, therefore, that the Duquesne-Kiowa-TNT transaction does not establish that the notes used in these transactions were shams. Rather, we believe that the presence of TNT in these transactions explains the agreements reached and establishes that CRC did not engineer a sham deal. Rather, Freel of Kiowa placed his company in an enviable position. Freel was able to contract with TNT so that TNT agreed to drill a well on the Singer prospect for less money than Freel obtained from CRC. Since TNT's obligation was no-log, no-pay, Freel was assured that TNT would make a good-faith effort to fulfill its contractual commitment. At the same time, Freel kept for Kiowa the completion option and a small amount of the cash received from CRC. In essence, Freel maneuvered Kiowa into a middle-man position in which

Kiowa was likely to benefit. Because Kiowa had passed much of the risk to a third party, TNT, Kiowa was able to assume the no-out turnkey drilling obligation.[62]

Moreover, the initial issue in this case is whether, as respondent charges, CRC simply tacked on notes to otherwise viable transactions simply to inflate the Investors' tax deductions. We conclude that the Duquesne-Kiowa-TNT transaction does not put CRC in such a light. Both Taylor and an independent engineer believed that the price which CRC paid for testing the Singer prospect was fair and reasonable. Additionally, when CRC and Kiowa arranged this transaction, CRC was unaware of TNT's presence.[63] This last fact is important, for Kiowa was willing to assume all the risks of the no-out turnkey drilling contract because it knew that it could pass much of those risks on to TNT. We conclude that CRC entered into a transaction with Duquesne and Kiowa in which CRC agreed to commercially reasonable terms in its usual cash/note format and that CRC was unaware that TNT had enabled Kiowa to reshape the transaction to its own advantage.

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62. In a sense, this transaction is similar to the Elpac transactions in that the operators in the Elpac transaction were willing to accept only the cash portion of the drilling price and the completion option because the operators were sharing risks with Elpac. Similarly, Kiowa was willing to assume all the risks of CRC's no-out turnkey drilling contract because it had agreed to share those risks with TNT.

As to why Kiowa brought Duquesne into this transaction, since Freel did not testify we do not know. It seems likely, however, that Freel did not want Kiowa to incur the tax liabilities associated with the notes when Freel had already arranged to share the risk of the contract with TNT.

63. Taylor did not originally approach CRC because he knew that CRC would not have heard of him. Taylor was at the closing with CRC, but CRC was unaware of the details of the TNT-Kiowa contract.

A further reason supporting our rejection of the sham characterization of the notes is that they did in fact lead to substantial payments in more than half of the 1972 packages. While the record fails to disclose the number of nonrecourse notes which were or will be fully paid, it does disclose that production was achieved in 13 of the 24 packages in which Coral I and Coral II participated, and in 15 of the 28 packages participated in by CRC individually. In the light of these figures, albeit they are hindsight, it is more difficult to shrug off the notes as economically meaningless. It appears, to the contrary, that some payment upon a majority of the notes could be expected. This is not to say, however, that the notes were ever worth anything close to their face value. Indeed, our findings show that in CRC's 1972 program a total of $52,000,000 of nonrecourse notes was issued, and that the anticipated total payments thereon, including interest, and before discounting for present value, viewed by hindsight in 1976, were only about $9,000,000. It is fair to say that the notes could only have had a market value when issued which was a small fraction of their face amount. However, it is impossible for us to shrug off even $9,000,000 as a sham of no commercial importance.

B. *Tax Treatment of the Notes*

Having concluded that the nonrecourse notes were not shams, we must next determine the proper characterization of these notes for tax purposes. Respondent contends that, even if the notes were not shams, they should not be treated as liabilities for tax purposes. Respondent points out that repayment of the liability evidenced by the notes was contingent upon the discovery of oil and gas. Accordingly, respondent contends that the notes should not be included in petitioners' bases in the partnerships in which petitioners invested. On the other hand,

petitioners contend that the notes are a fixed liability. In the alternative, petitioners contend that the notes should be treated as liabilities for tax purposes because the notes are production payments within the meaning of section 636. In either case, petitioners contend that the full amount of the nonrecourse notes should be added to their bases in their partnership interests.

Generally, a partner's share of partnership losses is limited to the extent of the adjusted basis of such partner's interest in the partnership at the end of the partnership year in which the loss occurred.[64] Section 704(d).[65]

64. As set forth in our Findings, the disputed deduction claimed by Coral I, Coral II and CRC for, primarily, intangible drilling and development costs led to a claimed loss at the partnership level. Respondent disallowed petitioner Brountas' deduction of his claimed share of this partnership loss.

65. During the years in issue, section 704(d) read as follows:

> (d) Limitation on Allowance of Losses.—A partner's distributive share of partnership loss (including capital loss) shall be allowed only to the extent of the adjusted basis of such partner's interest in the partnership at the end of the partnership year in which such loss occurred. Any excess of such loss over such basis shall be allowed as a deduction at the end of the partnership year in which such excess is repaid to the partnership.

For liabilities incurred after December 31, 1976, but before December 31, 1978, section 704(d) read as follows:

> (d) Limitation on Allowance of Losses.—A partner's distributive share of partnership loss (including capital loss) shall be allowed only to the extent of the adjusted basis of such partner's interest in the partnership at the end of the partnership year in which such loss occurred. Any excess of such loss over such basis shall be allowed as a deduction at the end of the partnership year in which such excess is repaid to the partnership. For purposes of this subsection, the adjusted basis of any partner's interest in the partnership shall not include any portion of any partnership liability with respect to which

A partner's adjusted basis in his interest in a partnership, to the extent such interest is, as here, acquired by contributions, is generally the amount of money and the adjusted basis of property contributed by the partner to the partnership, increased by his share of taxable income and certain deductions and decreased (but not below zero) by losses and nondeductible expenditures.[66] Section 705 and 722. However, section 752(a) provides that any increase in a partner's share of the liabilities of the partnership shall be considered as a contribution of money by such

65. (Cont'd.)

the partner has no personal liability. The preceding sentence shall not apply with respect to any activity to the extent that section 465 (relating to limiting deductions to amounts at risk in case of certain activities) applies, nor shall it apply to any partnership the principal activity of which is investing in real property (other than mineral property).

The last two sentences of section 704(d) were added as part of the Tax Reform Act of 1976; this change was made in conjunction with the at-risk limitations of section 465. Pub. L. No. 94-455, 90 Stat. 1520. For a discussion of the at-risk provisions enacted by the Tax Reform Act of 1976 and the Revenue Act of 1978, see note 39a, *supra*.

In the Revenue Act of 1978, section 704(d) was amended, effective for taxable years beginning after December 31, 1978, by removing the last two sentences of the section. Pub. L. No. 95-600, 92 Stat. 2763. In essence, section 704(d) was amended in 1978 to read exactly as it had read prior to the Tax Reform Act of 1976. The transitional rule in the Revenue Act of 1978 provides that in the case of a loss which was not allowed by reason of the last 2 sentences of section 704(d) (as enacted in the Tax Reform Act of 1976), such loss shall be treated as a deduction (subject to the at-risk provisions of section 465(a)) for the first taxable year after December 31, 1978. Section 201(b)(2), Pub. L. No. 95-600, 90 Stat. 2763.

66. The basis of an interest in a partnership acquired other than by contribution is governed by section 742.

partner to the partnership. In the case of a limited partnership, Regulations section 1.752-1(e) provides:

> (e) *Partner's share of partnership liabilities.* A partner's share of partnership liabilities shall be determined in accordance with his ratio for sharing losses under the partnership agreement. In the case of a limited partnership, a limited partner's share of partnership liabilities shall not exceed the difference between his actual contribution credited to him by the partnership and the total contribution which he is obligated to make under the limited partnership agreement. However, where none of the partners have any personal liability with respect to a partnership liability (as in the case of a mortgage on real estate acquired by the partnership without the assumption by the partnership or any of the partners of any liability on the mortgage), then all partners, including limited partners, shall be considered as sharing such liability under section 752(c) in the same proportion as they share the profits.[67]

The crux of the issue which we must decide is whether the nonrecourse notes constitute "liabilities" which are treated as a contribution of money to the partnerships and, therefore, are added to petitioners' bases. Petitioners are entitled to deduct losses incurred in the 1972 drilling program up to the full amount of their

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67. Section 752(c) provides that, for purposes of section 752, a liability to which property is subject shall, to the extent of the fair market value of such property, be considered as a liability of the owner of the property. For a complete discussion of section 752(c), see *Tufts v. Commissioner*, 70 T.C. 756 (1978), on appeal (5th Cir., Apr. 23, 1979).

bases.[68] Respondent determined, essentially, that petitioners' bases were limited to their cash contributions and, accordingly, disallowed excess claimed loss deductions. We conclude that for purposes of this case the notes are to be treated as production payments within the meaning of section 636 and are therefore to be treated as constituting liabilities for this purpose.[69]

1. Production Payments. Respondent does not contend that these arrangements should be characterized as joint ventures or partnerships between the operators and the limited partnerships, in which the "notes" denoted simply a contingent share of the mineral income to be earned by the operator as part of his distributive share of partnership income by virtue of the risks he assumed by taking on the no-out turnkey contract. Since this contention is not made, we need not and do not consider whether these arrangements should be so characterized. Both parties are in agreement that the lease seller and purchaser and owner-driller characterizations placed by the parties upon the relationship between the operators and the limited partnerships or CRC are to be accepted.

68. The amount of such losses—primarily, the amount of intangible drilling and development costs which Coral I, Coral II and CRC are entitled to deduct—is discussed *infra*. But the amount of such losses is relevant only to the extent of petitioners' bases in their partnership.

69. Because we conclude that the nonrecourse notes are production payments within the meaning of section 636, we do not reach respondent's argument that the notes should not be treated as liabilities because they are "contingent." In this argument, respondent asserted that no payments would be made on the notes unless oil or gas were found. Because repayment was completely dependent upon production of oil and gas, respondent argued that the notes constituted "contingent liabilities" which should not be treated as liabilities for tax purposes. We note that this argument supports our holding that the nonrecourse notes are production payments within the meaning of section 636.

In another case with similar facts if such re-characterization were urged, we would not view this opinion as precluding our examination of that question. We do not, however, consider it appropriate to consider or decide issues neither raised nor argued here by the parties.

Leaving aside for the moment the provisions of section 636, we could consider it highly doubtful that a predrilling production payment on an exploratory or so-called wildcat well, even when cross-collateralized with other wildcat wells, or any similar nonrecourse, highly contingent obligation would be a "liability" for purposes of section 752(a). This point is argued energetically by the parties, but we do not reach it because we consider the characterization of the obligation for section 752 purposes to be governed by section 636.

Petitioners contend, while respondent denies, that the nonrecourse notes at issue here should be treated as liabilities because the notes are production payments within the meaning of section 636. Section 636 provides in pertinent part:

> (a) *Carved-out Production Payment.*—A production payment carved out of mineral property shall be treated, for purposes of this subtitle, as if it were a mortgage loan on the property, and shall not qualify as an economic interest in the mineral property. In the case of a production payment carved out for exploration or development of a mineral property, the preceding sentence shall apply only if and to the extent gross income from the property (for purposes of section 613) would be realized, in the absence of the application of such sentence, by the person creating the production payment.
>
> (b) *Retained Production Payment on Sale of Mineral Property.*—A production payment retained

on the sale of a mineral property shall be treated, for purposes of this subtitle, as if it were a purchase money mortgage loan and shall not qualify as an economic interest in the mineral property.

(a) Background. The application and meaning of section 636 can only be understood in the context of the history of the tax treatment of income from oil and gas. The economic interest concept has been central to the taxation of income from depletable resources. In *Palmer v. Bender,* 287 U.S. 551 (1933), the Supreme Court held that a taxpayer has an economic interest in a mineral property if, first, he acquired this interest by investment in the minerals in place and, second, the taxpayer looks to the extraction of the minerals for the return of his investment. See *Weaver v. Commissioner,* 72 T.C. — (1979). The importance of the "economic interest" concept is that if the taxpayer owns an economic interest, the taxpayer is entitled to a deduction for depletion with respect to the income from the mineral property. *Palmer v. Bender, supra; Thomas v Perkins,* 301 U.S. 655 (1937).

Prior to the passage of the Tax Reform Act of 1969,[70] a production payment could constitute an economic interest eligible for the deduction for depletion. *Thomas v. Perkins, supra.* Generally, a production payment is a right to a specified share of the production from a specified mineral property when production occurs. F. Burke & R. Bowhay, Income Taxation of Natural Resources par. 2.07 (1979). However, in order for a production payment to constitute an economic interest, the holder of the production payment must, as a matter of substance and without regard to the formalities of conveyancing, look only to the production of oil and gas for payment. *Anderson v. Helvering,* 310 U.S. 404, 412-13 (1940). In *Ander-*

70. Pub. L. No. 91-172, 83 Stat. 483.

son v. Helvering, the Supreme Court held that a production payment which could be satisfied either from production or the proceeds of the sale of fee title to land conveyed did not constitute an economic interest. Other courts have subsequently held that a production payment is not treated as an economic interest if there is any security, or at least any substantial security, for payment (such as the income from other property or a lien on equipment on the property) other than production. *Standard Oil Co. (Indiana) v. Commissioner*, 465 F. 2d 246 (7th Cir. 1972), affg. 54 T.C. 1099 (1970); *Christie v. United States*, 436 F. 2d 1216 (5th Cir. 1971); *Lehigh Portland Cement Co. v. United States*, 433 F. Supp. 639 (E.D. Pa. 1977), affd. per order (3d Cir., May 12, 1978). The practical effect of classifying a production payment as an economic interest was that the holder of the production payment would receive ordinary income subject to cost or percentage depletion, while the mineral lessee (who had transferred or sold the production payment to its holder) was not taxed on the portion of production received by the holder. H. Rept. 91-413, 1969-3 C.B. 200.

The problem which arose—and which the Tax Reform Act of 1969 specifically addressed—was that production payments often resembled loans. This was exemplified in the so-called ABC transactions. In an ABC transaction, the owner of the mineral property, A, sells it to B, and reserves a production payment (bearing interest) for a portion of the purchase price. A then sells the production payment to C. The effect of this transaction was that C was entitled to depletion deductions and B could exclude from his income the amounts received by C. This was viewed as a problem by Congress:

> In the case of A-B-C transactions, taxpayers have been able to amortize or pay off what is essentially a

loan with before-tax dollars rather than after-tax dollars.[71]

H. Rept. 91-413, *supra*, 1969-3 C.B. at 287.

71. The House Report provides the following illustration of the problem:

> The factual similarity between the creation of a production payment and a loan transaction and the disparate tax treatment of production payments and loans can be illustrated by examining two hypothetical A-B-C transactions, one involving an oil payment, and the other the sale of an apartment.
>
> Assume that A sells an operating business to B—the business may be an oil well, or it may be an apartment building. However, assume that A retains the right to a production payment—a payment equivalent to the current price of a specified number of barrels of oil—or in the case of the apartment building, a mortgage, which is not much different from the production payment. Then suppose that A sells the production payment or mortgage to C.
>
> From A's standpoint, the two transactions are treated the same—they both result in a capital gain—or loss—to A depending upon his cost to other basis whether it is the apartment building or oil well which is being sold.
>
> However, the similarity between the oil well and the apartment building ends here. In the case of the apartment building, all of the rental income after ordinary expenses and depreciation is taxable income to B and he must pay off the mortgage out of "after tax" dollars.
>
> In the case of the oil well, however, B is not considered as receiving the production payment at all—which, in the typical case, may well amount to as much as 90 percent of the income from the well. Thus, in this case B is, in effect, paying the production payment out of "before-tax dollars." This privilege of paying off capital interests out of tax-free dollars is not a privilege accorded ordinary taxpayers. At the same time (until recently in the *Brook's* case), B, in the case of the oil well, claims the right to take the operating expenses for the entire well against his share of the income with the result he is likely to have hardly any taxes to pay while he is acquiring a full interest in the oil well.

Congress's response to this perceived problem was section 636, which provides that production payments are treated, for purposes of Subtitle A, as loans. This change was explained in the Committee Report as follows:

> For the above reasons, your committee's bill, in general, provides that production payment transactions are to be treated as loan transactions; that is, a loan by the owner of the production payment to the owner of the mineral property. This is the same treatment as provided under present law whenever the payout of a production payment, in the case of a carve out, is in any manner guaranteed by the person who created it, or, in the case of an A-B-C transaction, is guaranteed by B, the purchaser of the working interest.

H. Rept. 91-413, *supra*, 1969-3 C.B. at 287. A notable exception to this general provision is that production payments carved out for exploration or development of a mineral property are not treated as loans if, under the

71. (Cont'd.)

At the same time, B is paying little or no tax in the case of the oil well, C who is receiving the production payment is receiving cost depletion on this payment. Thus, he is amortizing his entire cost over the period he receives his payments.

The C who has the mortgage on the apartment house fares no better than his counterpart with the production payment despite the special advantages of the B with the oil well. The C with the mortgage can spread his cost over the period of the mortgage but, presumably, any excess he receives is interest income and therefore ordinary income.

The crucial difference between the A-B-C transaction in oil and the mortgage for the apartment, therefore, lies in the treatment of B and the fact that in the A-B-C transaction B can amortize C's capital interest out of tax-free dollars rather than the "after-tax dollars" he must use in the apartment case.

law prior to the Tax Reform Act of 1969, the person who created the production payment would not have realized gross income with respect to the income allocable to the production payment.[72] H. Rept. 91-413, *supra*, 1969-3 C.B. at 287. Since respondent does not invoke this exception, we need not consider whether it might be applicable here.

(b) Definition of a Production Payment. Petitioners contend, first, that the nonrecourse notes used in these transactions were production payments even if not labeled as such.[73]

Section 1.636-3(a), Income Tax Regs., defines production payments:

> (a) *Production payment.* (1) The term "production payment" means, in general, a right to a specified share of the production from mineral in

72. For example, if mineral lease owner A carved out a production payment in favor of X in consideration for X drilling an exploratory well on the lease, A would not realize gross income on this transaction and, therefore, the production payment would not be treated as a loan. H. Rep. No. 91-413, 91st Cong., 1st Sess. 287 (1969). Rather, the transaction is treated as a sharing arrangement as described in G.C.M. 22730, 1941-1 C.B. 214; see *Palmer v. Bender, supra,* and *Thomas v. Perkins, supra.* For a thorough discussion of sharing arrangements, see F. Burke & R. Bowhay, Income Taxation of Natural Resources chap. 7 (1979).

73. Respondent contends that the nonrecourse notes should not be viewed as production payments because the notes were completely devoid of economic substance. Respondent contends that the substance, rather than the form, of this transaction is determinative of its tax consequences. We have previously held that the notes did have economic substance, but we concur with respondent that the notes' substance, rather than their form, is determinative. It is for this reason that we are considering whether these notes were production payments within the meaning of section 636.

place (if, as, and when produced), or the proceeds from such production. Such right must be an economic interest in such mineral in place. It may burden more than one mineral property, and the burdened mineral property need not be an operating mineral interest. Such right must have an expected economic life (at the time of its creation) of shorter duration than the economic life of one or more of the mineral properties burdened thereby. A right to mineral in place which can be required to be satisfied by other than the production of mineral from the burdened mineral property is not an economic interest in mineral in place. A production payment may be limited by a dollar amount, a quantum of mineral, or a period of time. A right to mineral in place has an economic life of shorter duration than the economic life of a mineral property burdened thereby only if such right may not reasonably be expected to extend in substantial amounts over the entire productive life of such mineral property. The term "production payment" includes payments which are commonly referred to as "in-oil payments", "gas payments", or "mineral payments".

(2) *A right which is in substance economically equivalent to a production payment shall be treated as a production payment for purposes of section 636 and the regulations thereunder, regardless of the language used to describe such right, the method of creation of such right, or the form in which such right is cast (even though such form is that of an operating mineral interest). Whether or not a right is in substance economically equivalent to a production payment shall be determined from all the facts and circumstances.* An example of an interest which is to

be treated as a production payment under this subparagraph is that portion of a "royalty" which is attributable to so much of the rate of the royalty which exceeds the lowest possible rate of the royalty at any subsequent time (disregarding any reductions in the rate of the royalty which are based solely upon changes in volume of production within a specified period of no more than 1 year). For example, assume that A creates a royalty with respect to a mineral property owned by A equal to 5 percent for 5 years and thereafter equal to 4 percent for the balance of the life of the property. An amount equal to 1 percent for 5 years shall be treated as a production payment. On the other hand, if A leases a coal mine to B in return for a royalty of 30 cents per ton on the first 500,000 tons of coal produced from the mine in each year and 20 cents per ton on all coal in excess of 500,000 tons produced from the mine in each year, the fact that the royalty may decline to 20 cents per ton on some of the coal in each year does not result in a production payment of 10 cents per ton of coal on the first 500,000 tons in any year. Another example of an interest which is to be treated as a production payment under this subparagraph is the interest in a partnership engaged in operating oil properties of a partner who provides capital for the partnership if such interest is subject to a right of another person or persons to acquire or terminate it upon terms which merely provide for such partner's recovery of his capital investment and a reasonable return thereon. (Emphasis added.)

Section 1.636-3(a)(1) essentially adopts the historical definition of a production payment,[74] while section 1.636-

74. To the extent that section 1.636-3(a) provides that a production payment may burden more than one mineral property, the

3(a)(2) can be viewed as an expansion in that it treats as production payments rights which are not production payments but are in substance economically equivalent to production payments.

In this case, the nonrecourse notes were secured by (1) a percentage of the production from the package of wells, (2) the mineral leases for that package, and (3) any equipment on the property. Respondent contends that the mineral leases provided security which the recipients of the nonrecourse notes could look to if the wells were dry holes. Respondent also contends that if a well were completed, the equipment used in the completion attempt has considerable value and provides real collateral (other than the oil and gas, if any) for the notes. Accordingly, respondent contends, the nonrecourse notes were not economic interests under the rule set forth in *Anderson v. Helvering, supra.* In support of his position, respondent relies on *Christie v. United States,* 436 F.2d 1216 (5th Cir. 1971). In *Christie* the taxpayer carved out a "production payment" in favor of Karrenbrock in return for certain equipment; the production payment was equal to Karrenbrock's costs plus a commission plus interest. The production payment was also secured by any proceeds received from salvage of the equipment. The court in *Christie* held that, under the doctrine of *Anderson v. Helvering, supra,* Karrenbrock did not look solely to production for repayment and, therefore, Karrenbrock had not received a production payment.

We are unconvinced by respondent's arguments.[75] The alternative security here was not economically sig-

74. (Cont'd.)

definition appears to be broader than the historical definition. See *Lehigh Portland Cement Co. v. United States,* 433 F. Supp. 639 (E.D. Pa. 1977), affd. per order (3d Cir., May 12, 1978).

75. Respondent's position here contradicts his contention that the nonrecourse notes are contingent liabilities. When respondent

nificant. If all three wells in a package were dry holes, the security for the notes was basically worthless. There would not be any worthwhile salvageable equipment on the property, and the mineral lease for a property which has yielded a negative test well is virtually worthless.[76] As to the equipment used in completion attempts, the Joint Venture Agreement provided that the operator was entitled to recover all equipment used in the completion attempt. This right of the operator to recover the equipment was also recognized in the Loan Agreement which, in specifying collateral for the nonrecourse note, stated that such collateral was subject "to the terms and provisions of any instruments or agreements referred to [herein]." Accordingly, only the operator had a right to the equipment used in completion of the well.[77] There-

75. (Cont'd.)

contended that the notes should not be treated as liabilities, respondent asserted that "there will be no repayment if oil and gas is not found." Here, however, respondent argues that the notes could be repaid, at least partially, even if oil and gas were not found.

76. Such a mineral lease could, in rare instances, be farmed out to another party interested in testing the prospect, but as a general rule, and we have so found, such mineral leases had de minimis, if any, value. Nothing in the present record shows any residual value in any CRC lease after a dry hole had been drilled.

77. In most cases, in which the operator also held the nonrecourse note, this distinction was meaningless since the operator was entitled to the equipment under either the Loan Agreement or the Joint Venture Agreement. In the Elpac transactions, however, this distinction arguably had some validity. However, since CRC contracted with Elpac alone, Elpac-as-operator was entitled to the equipment used in completion under its agreements with CRC, even if such completion were attempted by the real operator, such as McMoRan. Presumably, when Elpac assigned its rights under the Joint Venture Agreement to McMoRan, McMoRan also obtained the security rights in the equipment used in a completion attempt.

fore, whether a prospect was a dry hole or completed, the holder of the nonrecourse note had, in reality, only the oil and gas found as security for the obligation.

There is a split of authority on whether characterization of an obligation as a production payment is precluded by even a remote and economically insignificant alternative, non-mineral source of payment, or only by an alternative source of economic significance. In *Standard Oil Co. (Indiana) v. Commissioner*, 465 F. 2d 246 (7th Cir. 1972), affg. 54 T.C. 1099 (1970), on which petitioners rely, the economic significance test was applied. But in *Christie v. United States, supra*, relied upon by respondent, it was held that even what was probably an economically insignificant possible alternative source of payment barred characterization of an obligation as a production payment. On the facts before us, it is clear that interests other than oil and gas in place nominally secured the nonrecourse notes. It is also clear that in the event of a dry hole this added security would be devoid of economic significance. We have so found, and respondent in fact correctly urges as much in making his sham argument. We would therefore have to face and resolve the *Christie-Standard Oil* question were it not for the first two sentences of Regulations section 1.636-3(a)(2). These sentences make it clear that an interest economically equivalent to a production payment is to be treated as one for purposes of section 636. Accordingly, whether or not the interests in question were production payments, they do not fall outside section 636 merely because of the economically insignificant added security. They are either production payments or they are the economic equivalent. Since neither party has attacked the validity of Regulations section 1.636-3(a)(2), we assume its validity for present purposes, and hold that the added security does not bring the nonrecourse note outside section 636.

There is, we think, a possibly more substantial reason for questioning the applicability of section 636 to this type of payment, but it is not raised by respondent. We deal here with exploratory wells—wildcats. The most probable duration of production from an exploratory well is zero—most are not producers. Yet an obligation to pay a share of mineral extending to or beyond the probable productive life of the well is not a production payment, either as classically conceived, *United States v. Morgan*, 321 F. 2d 781 (5th Cir. 1963), or under the fourth sentence of Regulations section 1.636-3(a)(1): "Such right must have an expected economic life (at the time of its creation) of shorter duration than the economic life of one or more of the mineral properties burdened thereby." Because of the cross-collateralization here it is of course less clear that the expected productive life is zero, but hindsight here shows a low probability of achieving full pay out for any given package. It could perhaps be argued, therefore, that the interests in question were not really production payments or the economic equivalent because under the circumstances they did not have economic lives of shorter duration than the most likely productive life of the property. Hindsight shows that full pay out will be the exception rather than the rule. However, respondent may have good reasons of his own for not urging an interpretation of section 636 which would effectively restrict it to development wells or known producers. Because the point has not been briefed or argued, we would consider it inappropriate to decide it. We note it here merely to clarify the fact that we have not decided it and that in a future case the point remains open.

Finally, it could be argued that the cross-collateralization itself removes the obligations from the classic category of production payments. However, here the Regulations seem to preclude such a contention by permitting

a production payment to "burden more than one mineral property" for purposes of section 636, and respondent does not make the contrary argument. Section 1.636-3(a)(1), Income Tax Regs.

In order to establish that these notes were not substantially equivalent to production payments, respondent also relies on a written opinion which petitioners received from their counsel. This opinion concluded that section 636 was inapplicable to these notes because of the security available; the opinion further concluded that the notes would be treated as liabilities because they represented true indebtedness. We are not persuaded by respondent's argument. In the first place, this opinion was based on the proposed regulations, which did not provide that a production payment could be paid from more than one mineral property.[78] Second, neither we nor petitioners are bound by an opinion received from their counsel.

We are left, therefore, with the conclusion that for purposes of this case section 636 must be treated as applicable. The arguments against its applicability are either unraised or untenable.

We have carefully weighed all the facts and circumstances concerning these nonrecourse notes, including particularly their collateral and the manner in which they were labeled by CRC and treated by the operators.[79] Section 1.636-3(a)(2) provides that if the facts and circumstances indicate that a right is in substance economically equivalent to a production payment, it shall be treated as such regardless of its name. On the basis of the facts and arguments made, we conclude that these nonrecourse notes are to be treated as production pay-

78. See note 74 *supra*.

79. We note that labeling these production payments as nonrecourse notes was not deceptive, since production payments are treated as loans.

ments within the meaning of section 1.636-3(a), Income Tax Regs., and their tax treatment should be determined under section 636 for purposes of this case.

In this case, the parties did not address the question whether these nonrecourse notes constitute carved-out production payments or retained production payments. See section 1.636-1(a)(1)(i), Income Tax Regs. A production payment created and retained upon the transfer of the mineral property is a retained production payment, while a production payment is carved out if the property remains in the hands of the person carving out the production payment immediately after the transfer of such production payment. This distinction is important in that retained production payments are treated as purchase money mortgages, while carved-out production payments are treated as mortgage loans on the property burdened thereby. Both types of production payments, however, are treated as loans under section 636. But, to the extent the nonrecourse notes are treated as "retained" production payments, the amount represented thereby would be analyzed under section 636(b) as constituting payment for the transferred leasehold interest rather than for performance of the drilling contract. This would presumably render such amount ineligible for inclusion in petitioners' intangible drilling costs.

We have given careful consideration to whether the nonrecourse notes in this case constitute retained or carved-out production payments. We conclude that the answer as to the part of the note which relates to the lease purchase is different from the answer as to the part of the note which relates to the drilling contract. The note portion of the lease purchase price was created upon the transfer of mineral interests by the various operators to the partnerships. In essence, the note portion of the lease purchase price was just that—a portion of the purchase

price. Since this portion of the note arose upon the transfer of mineral interests, it was a retained production payment and is treated as a purchase money mortgage. On the other hand, the note portion of the drilling contract price did not arise from the transfer of mineral interests. Rather, the note portion of the drilling contract price was merely a part of the payment for services received by the operators. The mineral interests, which the partnerships had purchased from the operators, were not transferred as part of the drilling contract. Accordingly, the note portion of the drilling contract price was a carved-out production payment, treated as a mortgage loan. While the contractual allocation of the total note amount between the two elements is not necessarily conclusive either upon respondent or upon the Court, respondent has not challenged the allocation in this case and it appears to be at least generally in accord with commercial practice. We do not disturb it.

(c) Application of Section 636. In essence, section 636 provides that production payments are treated as loans. Specifically, section 1.636-1(a), Income Tax Regs., provides:

> §1.636-1. Treatment of production payments as loans.
>
> (a) *In general.* (1)(i) For purposes of subtitle A of the Internal Revenue Code of 1954, a production payment (as defined in paragraph (a) of §1.636-3) to which this section applies shall be treated as a loan on the mineral property (or properties) burdened thereby and not as an economic interest in mineral in place, except to the extent that §1.636-2 or paragraph (b) of this section applies. See paragraph (b) of §1.611-1. A production payment carved out of mineral property which remains in the hands of the

person carving out the production payment immediately after the transfer of such production payment shall be treated as a mortgage loan on the mineral property burdened thereby. A production payment created and retained upon the transfer of the mineral property burdened by such production payment shall be treated as a purchase money mortgage loan on the mineral property burdened thereby. Such production payments will be referred to hereinafter in the regulations under section 636 as carved-out production payments and retained production payments, respectively. Moreover, in the case of a transaction involving a production payment treated as a loan pursuant to this section, the production payment shall constitute an item of income (not subject to depletion), consideration for a sale or exchange, a contribution to capital, or a gift if in the transaction a debt obligation used in lieu of the production payment would constitute such an item of income, consideration, contribution to capital, or gift, as the case may be. For the definition of the term "transfer" see paragraph (c) of §1.636-3.

(ii) The payer of a production payment treated as a loan pursuant to this section shall include the proceeds from (or, if paid in kind, the value of) the mineral produced and applied to the satisfaction of the production payment in his gross income and "gross income from the property" (see section 613 (a)) for the taxable year so applied. The payee shall include in his gross income (but not "gross income from the property") amounts received with respect to such production payment to the extent that such amounts would be includible in gross income if such production payment were a loan. The payer and payee shall determine their allowable deductions as

> if such production payment were a loan. See section 483, relating to interest on certain deferred payments in the case of a production payment created and retained upon the transfer of the mineral property burdened thereby, or in the case of a production payment transferred in exchange for property. See section 1232 in the case of a production payment which is originally transferred by the corporation at a discount and is a capital asset in the hands of the payee. In the case of a carved-out production payment treated as a mortgage loan pursuant to this section, the consideration received for such production payment by the taxpayer who created it is not included in either gross income or "gross income from the property" by such taxpayer.

The effect of this Regulation is fairly straightforward. If a property right is a production payment (as defined), that right is to be treated as a loan.[80] When a production payment is treated as a loan, it is treated "as if" the recipient (holder) of the production payment loaned money, equipment or services to the creator of the production payment, in return for which the recipient received the rights under the production payment. When production is realized and the holder of the production payment is paid, the payments are treated as repayment of the liability created by the loan. See section 1.636-1(a)(3), Example (1), Income Tax Regs. See also H. Rept. 91-413, *supra*, 1969-3 C.B. at 287. Since the production payment is treated as a loan for all purposes under Subtitle A, the interest

80. It is for this reason that we have concluded that respondent's contention that these nonrecourse notes were too contingent to be treated as liabilities was inapposite—since the notes are, in reality, production payments, they are treated as loans, regardless of whether payment is speculative.

component of the production payment is deductible by the creator under section 163. Section 1.636-1(a)(3), Example (1), Income Tax Regs. The production payment is accorded by section 636 the status of a liability.[81]

It is ironic, perhaps, that a section of the statute intended to eliminate an abuse has here had the unplanned side effect of assisting the erection of a shelter. However, the statute is clear. For all purposes of tax law, even an interest which is not objectively a debt must be treated as a debt if it is described in section 636. The nonrecourse notes here must be viewed as being so described, at least until respondent determines to make arguments which would tend to narrow the scope of that section.

We are not the first to perceive this anomaly. In a thoughtful discussion of the use of nonrecourse financing in the oil and gas industry, Professor Fiedler noted:

> [A nonrecourse obligation] may properly be reclassified as the sale of a carved-out production payment from two or more properties. If the burdened property consists only of economic interests in two

81. Because production payments are treated as liabilities, we conclude that respondent's reliance on section 446 is misplaced. Respondent contends that neither legal liability nor the amount due on the production payments is fixed, so that the "all events" test has not been satisfied. See section 1.446-1(c)(1)(ii), Income Tax Regs. However, a production payment is treated as a legal liability when it is treated as a loan under section 636. This treatment is exemplified by the fact that interest due on the production payment as to which the same argument could be made is deductible under section 163. See section 1.636-1(a)(3), Example (1), Income Tax Regs. The amount of such liability is also fixed at the total amount to be paid from production.

Respondent has not contended that the notes should be treated as production payments carved out for exploration and development within the meaning of the second sentence of section 636(a) and section 1.636-1(b), Income Tax Regs. Hence we need not and do not consider that issue.

> or more properties, and if the indebtedness may reasonably be expected to pay out prior to the termination of the productive life of the burdened property, and if it was factually determined that the transaction was not the sale of a development production payment, then under the law existing prior to the Tax Reform Act of 1969, the transaction would have been classified as the sale of a carved-out production payment. [*Commissioner v. P.G. Lake, Inc.*, 356 U.S. 260 (1958).] Such a sale would result in the immediate realization of income by the seller and would result in the capitalization of the funds advanced by the purchaser as his cost in the purchased production payment. However, section 636, added by the Tax Reform Act of 1969, and the Proposed Regulations promulgated thereunder, clearly seem to classify such a transaction as a mortgage loan with all of the tax consequences of a true loan following in succession. The effect is ironic. A nonrecourse loan which is not to be treated as a true loan on the basis of an examination of all its facts and circumstances is then, by statute, reclassified into the equivalent of a true loan. Perhaps one may conclude to his mild amusement that the Treasury, as it has before, won too much when it persuaded Congress to enact Section 636 and must now suffer to be hoist on its own petard.

Fiedler, "Drilling Funds and Nonrecourse Loans—Some Tax Questions," 24 Oil & Gas L. & Tax Inst. 527, 546-47 (1973) (citations omitted). See also section 761(a) and section 1.761-2, Income Tax Regs.

2. *Basis.* Petitioners can deduct their share of partnership losses only to the extent of the basis which petitioners have in their partnership interest. Section 704(d).

In general, a partner's basis in his partnership interest is increased by his share of the liabilities of the partnership. Section 752(a). This general rule also applies to nonrecourse obligations of a limited partnership if no partner is individually liable for such obligation. Section 1.752-1(e), Income Tax Regs. In this case, however, respondent contends that petitioners' bases are not increased in the amount of the nonrecourse notes because the property securing such notes was too speculative to have value. In support of this position, respondent relies on section 752(c), which provides:

> *(c) Liability to Which Property is Subject.*— For purposes of this section, a liability to which property is subject shall, to the extent of the fair market value of such property, be considered as a liability of the owner of the property.

At first blush, section 752(c) appears to limit petitioners' bases to the fair market value of the property securing the nonrecourse notes; that is, basis would be increased by the value of anticipated oil and gas production, if any, determined before drilling has commenced. Respondent contends that this value was zero. Petitioners, on the other hand, contend that the property securing the notes had considerable value. We have not, however, determined the value of such property because we do not believe that it is necessary. Rather, we conclude on the basis of our decision in *Tufts v. Commissioner*, 70 T.C. 756 (1978), on appeal (5th Cir., April 23, 1979), that petitioners' bases increased in the full face amount of the nonrecourse notes.

In *Tufts* the taxpayers were partners in a general partnership which owned an apartment complex. The taxpayers sold their partnership interests to a third party, who paid them no consideration other than fees but who

took the property subject to a nonrecourse mortgage. At the time of this sale, the apartment complex had a fair market value of $1,400,000; the mortgage was $1,851,500. The partners' aggregate adjusted basis was $1,455,740. In *Tufts* the taxpayers argued, on the basis of section 752(c), that the excess of their relief from the nonrecourse liabilities ($1,851,500) over their basis in the partnership interests ($1,455,740) should be included in the gain they realized only to the extent of any excess of the fair market value of the property ($1,400,000) over such basis, and that in that case such excess was zero. They contended that the fair market value limitation of section 752(c) applied to sales of partnership interests under section 752(d).[82] Respondent, on the other hand, contended that section 752(c) is narrow in scope and applies only in connection with sections 752(a) and (b), relating to contributions to and distributions from the partnership or amounts treated as such contributions or distributions.

We basically agreed with respondent. We held in *Tufts* that the fair market value limitation of section 752(c) does not apply to the sale of a partnership interest under section 752(d). In reaching this conclusion, we relied particularly on the portion of the legislative history of section 752(c) which stated:

> Frequently, a partner will assume partnership liabilities or a partnership will assume a partner's liabilities. In some cases this occurs as a result of a contribution of encumbered property by the partner to the partnership or as the result of a distribution

82. Section 752(d) provides:

(d) *Sale or Exchange of an Interest.*—In the case of a sale or exchange of an interest in a partnership, liabilities shall be treated in the same manner as liabilities in connection with the sale or exchange of property not associated with partnerships.

> of such property by the partnership to the partner. The provisions of this section prescribe the treatment for such transferred liabilities. * * *
>
> * * *
>
> The transfer of property subject to a liability by a partner to a partnership, or by the partnership to a partner, shall, to the extent of the fair market value of such property, be considered a transfer of the amount of the liability along with the property.

H. Rept. 1337, to accompany H.R. 8300 (Pub. L. 591), 83d Cong., 2d Sess. A236 (1954). We also pointed to section 1.752-1(c), Income Tax Regs., which adopted this limited view of section 752(c):

> *(c) Liability to which property is subject.* Where property subject to a liability is contributed by a partner to a partnership, or distributed by a partnership to a partner, the amount of the liability, to an extent not exceeding the fair market value of the property at the time of the contribution or distribution, shall be considered as a liability assumed by the transferee. * * *

We concluded that the statutory language was ambiguous and that, in light of the legislative history and the Regulations, the better interpretation of section 752(c) was that its limitation only applies with respect to the contribution or distribution of encumbered property, or with respect to amounts treated as such contributions or distributions. 70 T.C. at 769.

It could be argued that *Tufts* does not reach the question presented here. Indeed, this view of *Tufts* was adopted by the District Court in *Gibson Products Co. v. United States,* 460 F. Supp. 1109 (N.D. Tex. 1978), on

appeal (5th Cir.,May 18, 1979), which relied on a footnote in our *Tufts* opinion.[83] We conclude, however, that both the reasoning of *Tufts* and the legislative history on which we relied in that decision are dispositive here.

As to the legislative history and section 1.752-1(e), Income Tax Regs., both support the view that Congress had in mind only two situations to which it believed that section 752(c) would apply: the contribution of encumbered property by a partner to a partnership, and the distribution of encumbered property by the partnership to a partner. 70 T.C. at 768. There is no indication in either the legislative history or the Regulations that Congress intended section 752(c) to limit the increase of a partner's basis when the partnership, as an entity, assumes a liability. We believe that our decision in Tufts correctly limited the scope of section 752(c) in line with its legislative history and the Regulations, and such limitation (which respondent urged in *Tufts*) should also apply here.

Moreover, the reasoning of Tufts mandates that the full amount of the nonrecourse notes be included in petitioners' bases. *Tufts* is a lineal descendent of *Crane v. Commissioner*, 331 U.S. 1 (1947), in which the Supreme Court held that the amount of a nonrecourse mortgage is included in the owner's basis and in the amount realized

83. Footnote 13 in *Tufts* states:

We do not pass upon whether nonrecourse liabilities in excess of the fair market value of the property securing such liabilities are included in the basis of a partnership interest acquired by purchase. Compare *Bolger v. Commissioner*, 59 T.C. 760, 769-771 (1973); *Mayerson v. Commissioner*, 47 T.C. 340, 351-354 (1966); *Blackstone Theatre Co. v. Commissioner*, 12 T.C. 801, 804 (1949), with *Morris v. Commissioner*, 59 T.C. 21, 33-34 (1972); see 1 W. McKee, [W. Nelson, and R. Whitmire, Federal Taxation of Partnerships and Partners, par. 7.04] at 7-14-7-15 [1977].

70 T.C. at 770 n. 13.

upon disposition of the property.[84] The *Crane* doctrine is basically a symmetrical one—a taxpayer includes nonrecourse liabilities in his basis, but he must also include such liabilities in the amount he realizes upon disposition of the encumbered property. The application of the *Crane* doctrine here can be illustrated by the following example. If petitioner Brountas had sold his partnership interest in Coral I the day after Coral I contracted with the various operators (but before any wells were drilled), presumably he should recognize neither gain nor loss. This assumes that all contracts were fair and reasonable, as we have found. In essence, his economic position was unchanged, and the sale should reflect this fact. However, under *Tufts* the amount realized by Brountas would include the full face amount of his proportionate share of Coral I's nonrecourse liabilities unlimited by the value of the security. Yet Brountas should not have any gain or loss for tax purposes, despite the inclusion at face of the nonrecourse liabilities in the amount realized. This result is reached under the *Crane* doctrine because Brountas' basis would also be increased in the amount of those liabilities. In other words, the reason *Tufts* requires that a taxpayer include in the amount realized upon the sale of a partnership interest the full amount of nonrecourse liabilities—not just the fair market value of the security—is that that full amount is also included in determining the taxpayer's basis in his partnership interest. 70 T.C. at 769. Otherwise, as we noted in *Tufts*, taxpayers could deduct partnership losses with respect to their bases (including nonrecourse liabilities) but could avoid accounting for such deductions upon the disposition of their partnership interests, a result which *Crane* sought to

84. We noted in *Tufts* that section 752 is generally regarded as a codification of the *Crane* doctrine for purposes of determining the basis of a partner's interest in a partnership. 70 T.C. at 767.

prohibit. *Id.* In essence our decision in *Tufts* adopts the symmetry inherent in the *Crane* doctrine.

In reaching our conclusion that the full amount of the nonrecourse notes included in petitioners' bases, we have been mindful of the position which respondent adopted in *Tufts*. Respondent there argued that since petitioners could include the full amount of the liabilities in their bases, this full amount must also be recognized upon disposition of the property.[85] In essence, respondent argued in *Tufts* that the fair market value of the property should not be considered except in the limited situation of the contribution or distribution of encumbered property, and we accepted respondent's assertions and reached our decision accordingly. To accept respondent's position in this case, however, would disrupt the symmetrical balance which we achieved in *Tufts*. We see no reason to allow respondent to retreat here from the argument he made—persuasively—in *Tufts* that a partner's basis includes the full amount of nonrecourse liabilities except in the situations expressly delimited in section 1.752-1(c), Income Tax Regs. Accordingly, we conclude that petitioners' bases include the full amount of the nonrecourse notes

85. Respondent stated his position in *Tufts* as follows:

> It is respondent's position that under *Code* §§ 752(a) and 722 as well as the decision in the case of *Crane v. Commissioner*, 331 U.S. 1 (1947), each partner received a basis in the partnership equal to the amount of their pro rata share of the nonrecourse liabilities of the partnership plus any contributions. During the operation of the partnership each partner's basis was reduced under *Code* § 705 by any losses and depreciation incurred or taken by the partnership. When each partner sold his partnership interest to Mr. Bayles each partner was required to report as gain, under *Code* § 752(d) the difference between their adjusted basis in the partnership and the liabilities owed on the partnership property.

Brief for Respondent at 18, *Tufts v. Commissioner*, 70 T.C. 756 (1979), on appeal (5th Cir., Apr. 23, 1979).

which were given to the various operators as part of the consideration in these transactions.

C. Amount of Intangible Drilling and Development Costs Incurred.

We must next determine the amount of intangible drilling and development costs ("IDCs") which Coral I, Coral II and CRC incurred. Respondent contends that the partnerships only incurred IDCs to the extent of the cash portion of the no-out turnkey drilling contract prices; in essence, respondent contends that the cash was the only consideration given to the operators for their drilling obligations. Petitioners, on the other hand, contend that the partnerships incurred IDCs at least equal to the drilling contract prices since each package of consideration given to the various operators (i.e., cash, note and completion option) was worth at least the face value of the no-out turnkey drilling contract. For reasons set forth below, we agree with petitioners.

Section 263(c) provides that regulations shall be prescribed which grant an option to deduct as expenses IDCs in the case of oil and gas wells. In accordance with this statutory provision, section 1.612-4, Income Tax Regs.,[86]

86. Section 1.612-4(a), Income Tax Regs., provides:

Charges to capital and to expense in case of oil and gas wells.

(a) *Option with respect to intangible drilling and development costs.* In accordance with the provisions of section 263(c), intangible drilling and development costs incurred by an operator (one who holds a working or operating interest in any tract or parcel of land either as a fee owner or under a lease or any other form of contract granting working or operating rights) in the development of oil and gas properties may at his option be chargeable to capital or to expense. This option applies to all expenditures made by an operator for wages, fuel, repairs, hauling, supplies, etc., incident to and necessary for the drilling of wells and the preparation of wells

86. (Cont'd.)

for the production of oil or gas. Such expenditures have for convenience been termed intangible drilling and development costs. They include the cost to operators of any drilling or development work (excluding amounts payable only out of production or gross or net proceeds from production, if such amounts are depletable income to the recipient, and amounts properly allocable to cost of depreciable property) done for them by contractors under any form of contract, including turnkey contracts. Examples of items to which this option applies are all amounts paid for labor, fuel, repairs, hauling, and supplies, or any of them, which are used—

(1) In the drilling, shooting, and cleaning of wells,

(2) In such clearing of ground, draining, road making, surveying, and geological works as are necessary in preparation for the drilling of wells, and

(3) In the construction of such derricks, tanks, pipelines, and other physical structures as are necessary for the drilling of wells and the preparation of wells for the production of oil or gas.

In general, this option applies only to expenditures for those drilling and developing items which in themselves do not have a salvage value. For the purpose of this option, labor, fuel, repairs, hauling, supplies, etc., are not considered as having a salvage value, even though used in connection with the installation of physical property which has a salvage value. Included in this option are all costs of drilling and development undertaken (directly or through a contract) by an operator of an oil and gas property whether incurred by him prior or subsequent to the formal grant or assignment to him of operating rights (a leasehold interest, or other form of operating rights, or working interest); except that in any case where any drilling or development project is undertaken for the grant or assignment of a fraction of the operating rights, only that part of the costs thereof which is attributable to such factional interest is within this option. In the excepted cases, costs of the project undertaken, including depreciable equipment furnished, to the extent allocable to fractions of the operating rights held by others, must be capitalized as the depletable capital cost of the fractional interest thus acquired.

provides that the holder of a working or operating interest may elect to deduct IDCs. This election applies to all expenditures made by the holder of the working or operating interest for wages, fuel, repairs, etc. which do not have a salvage value. In this case, Coral I, Coral II and CRC validly elected to deduct IDCs.

Respondent first contends that Coral I, Coral II and CRC incurred "expenditures", hence IDCs, only in the amount of the cash portion of the drilling contract prices. Respondent's contention has two grounds. First, respondent contends that the nonrecourse notes given to the various operators were worthless shams. Second, respondent asserts that the completion options were not transferred to the operators; rather, respondent contends that the operators retained the interests under the completion options when the packages were sold to the partnerships. The crux of respondent's two arguments is that the operators received no consideration other than cash for their no-out turnkey drilling commitments.

We conclude that the facts belie respondent's assertions. In the first place, we have previously concluded that the nonrecourse notes were not shams; although we have not set an exact value on the notes, they were not worthless. Rather, the notes were a valuable portion of the consideration which flowed from the partnerships to the operators. Second, there is no factual support for respondent's assertion that the operators retained the interests which they eventually acquired when they exercised their completion options. Instead, the record is replete with evidence (credible testimony and contracts) which establishes that the operators transferred to the partnerships the contracted-for leasehold interests in the Lease Purchase and Turnkey Drilling Agreements. Only through exercise of the completion option, which required

considerable expenditure by the operator, could the operator regain a portion of the working interest.[87]

The next question raised by respondent is the fair market value of the consideration which the partnerships gave to the various operators for the no-out turnkey drilling commitments. Respondent contends that the package of consideration—i.e., cash, note and completion option—was worth only the amount of cash, while petitioners contend that such consideration was worth at least the total price (cash plus note portion) of the drilling contract.

It may be that the necessary corollary of section 636 treating the production payment (nonrecourse note) as a liability for all purposes of tax law is that IDCc purchased by taking subject to such liability are fully deductible even if the liability is worth less than face due to its contingent nature. However, we need not reach this question, for we conclude that the evidence sustains petitioners' view of the fair market value of the consideration transferred to the various operators. Numerous operators testified, candidly and credibly, that they would not have undertaken the no-out turnkey drilling commitments for the total contract price in cash alone. Rather, the operators required a package of rights which gave them an opportunity to share in production, if any. By this testimony, the operators established that they viewed the package of rights transferred by the partnerships as worth

87. To the extent that respondent's position is that, in substance, the operators retained the working interest, again the facts do not support this contention. Many operators testified that they viewed the completion option as one of the pieces of consideration which they received from the partnerships in this transaction. This testimony contradicts respondent's assertion that the operators retained such an interest. Had the operators retained the working interest, they would have been entitled to deduct IDCs, which none of them claimed.

no less than the total contract prices.[88] Respondent presented no credible evidence to the contrary. Since petitioners claimed deductions for IDCs only in the amount of the drilling contract prices, we do not have to establish the exact value of the consideration transferred to the operators. It is sufficient for purposes of this decision that such consideration had a fair market value not less than the drilling contract prices.

Regulations section 1.612-4 allows the holder of the working interest currently to deduct all IDCs which are incurred. In this case, the partnerships which owned the working interests gave to various operators a package of rights (cash, note and completion option) with a value at least equal to the drilling contract prices for the no-out turnkey drilling obligations which the operators undertook. All contracted-for drilling was performed. We conclude that the consideration conveyed—property worth at least the drilling contract prices—constituted compensation to the operators for the services which they performed, section 1.61-2(d), Income Tax Regs., and such amounts were intangible drilling and development costs within the meaning of section 1.612-4(a), Income Tax Regs. The partnerships were entitled to deduct these IDCs.[89]

II. Interest

In his statutory notices, respondent determined that Coral I, Coral II and CRC were not entitled to deductions for interest with respect to the nonrecourse notes. The notes bore interest at a rate of 6½ percent per annum.

88. If the consideration were worth less, the operators would have preferred the total contract price in cash.

89. Because of our conclusion, we do not address petitioners' alternative contention that they are entitled to deductions under section 83.

Respondent argues that these claimed interest deductions were improper because the notes were shams.

We disagree with respondent. Specifically, we have concluded above that the notes were not shams and that the notes, which constitute production payments, are treated as valid liabilities for tax purposes. Section 636. With respect to the claimed interest deduction, we believe that one of the examples in the Regulations is dispositive:

> *Example (1).* On December 22, 1972, A, a cash-basis calendar-year taxpayer who owns operating mineral interest X, carves out of X a production payment in favor of B for 300,000 plus interest, payable out of 50 percent of the first oil produced and sold from X. In 1972, A treats the $300,000 received from B for the production payment as the proceeds of a mortgage loan on X. In 1973, A produces and sells 125,000 barrels of oil for $373,500. A pays B $186,750 with respect to the production payment, $168,750 being principal and $18,000 being interest. In computing his gross income and "gross income from the property" for the year 1973, A includes the $373,500 and takes as deductions the allowable expenses paid in production of such mineral. *A also takes a deduction under section 163 for the $18,000 interest paid with respect to the production payment.* For 1973, B would treat $18,000 as ordinary income not subject to the allowance for depletion under section 611.

Section 1.636-1(a)(3), Example (1), Income Tax Regs. [Emphasis added.] Accordingly, we conclude that Coral I, Coral II and CRC are entitled to the claimed interest deductions.

III. Advanced Royalties

Coral I, Coral II and CRC claimed deductions in 1972 for "advanced royalties." The alleged advanced royalties

were equal to the note portions of the stated lease purchase prices under the Lease Purchase and Turnkey Drilling Agreements which were entered into with the various operators. In his statutory notices, respondent determined that these claimed deductions were improper because, first, they were premature and, second, no deductions are allowable with respect to the notes which are shams.

An advanced royalty is one form of payment by a lessee to a lessor when mineral interests are transferred. A payment by the lessee to the lessor is an advanced royalty if the payment is recoverable by the lessee out of the lessor's share of future production. Fielder, "The Lessor, the Less and the Income Tax," 14 Southwestern Legal Foundation Inst. on Oil and Gas Taxation 361, 389 (1963). Other possible forms which a payment by a lessee to the lessor could assume, none of which are so recoverable, include bonuses, rentals or delay rentals. Advanced royalties, as defined in section 1.612-3(b), Income Tax Regs., can at the election of the lessee be deducted in the year paid or accrued. Section 1.612-3(b)(3), Income Tax Regs.

Petitioners contend that the note portions of the stated lease purchase prices constitute advanced royalties. We disagree. Petitioners' characterization of these payments as advanced royalties relies on categorizing these payments within the context of a mineral lease, while we conclude that Coral I, Coral II and CRC acquired mineral interests by purchase. Although the mineral interest acquired was a mineral lease, the question here is not what is the interest acquired but how it was acquired. Cf. *Helvering v. Elbe Oil Land Development Co.*, 303 U.S. 372 (1938). If the transferor of a mineral interest does not retain an economic interest in the mineral property, the transaction is normally treated as a sale. *Cox v. United States*, 431 F. 2d 1360, 1362 (10th Cir. 1970),

cert. denied, 402 U.S. 905 (1971). See *Glenn v. Commissioner*, 39 T.C. 427 (1962), in which the vendor retained a production payment as part of the consideration for the transfer of his mineral interests. We held that the transaction was a sale, not a lease. Concepts such as "advanced royalties" have no application to a purchased mineral interest; the purchaser capitalizes his costs and recovers them through depletion. Fielder, "The Lessor, the Lessee and the Income Tax," *supra* at 383; F. Burke & R. Bowhay, Income Taxation of Natural Resources par. 5.08 (1979).

Our conclusion that petitioners purchased their mineral interests is based, primarily, on the language by which such conveyances were made. For example, in an Elpac transaction, the lease purchase portion of the Lease Purchase and Turnkey Drilling Agreement provided:

> By its execution hereof, ELPAC hereby BARGAINS, SELLS, ASSIGNS and CONVEYS to CRC all of ELPAC's rights in and to the Oil and Gas Leases covering [the prospects in the package], and agrees to furnish to CRC recordable assignments of such interest in such leases, with special warranty of title, on or before December 31, 1972.

This language of assignment conforms perfectly to the usual definition of a sale of oil and gas property, namely, when the owner of a property interest assigns all or an undivided fraction of his interests to another person. F. Burke & R. Bowhay, *supra*, at par. 3.03; Fielder, "The Lessor, the Lessee and the Income Tax," *supra* at 383. In return for its leasehold interests conveyed, the various operators were paid by the partnerships a negotiated-for amount; the operators received payment in the form of cash, and such portion of the completion option and nonrecourse note as was allocated to the lease rather than to

the drilling contract. (As noted, such allocations are not contested here.)

Whether this transaction actually constituted a sale or a lease is a factual question on which petitioners bear the burden of proof. *Welch v. Helvering*, 290 U.S. 111 (1933); Rule 142(a), Tax Court Rules of Practice and Procedure. They have offered neither evidence nor argument rebutting the form of the transaction.[90] Cf. *Commissioner v. Danielson*, 378 F. 2d 771 (3d Cir. 1967), cert. denied 389 U.S. 858 (1967). Indeed, we have previously upheld petitioners' contentions that their format had economic reality. We believe this applies to the sales of the mineral interests as well as the nonrecourse notes. Accordingly, we hold that Coral I, Coral II and CRC must capitalize the note portions of the lease purchase prices paid.

IV. Management Fees

In 1972 Coral I and Coral II claimed deductions for management fees. These fees, 18 percent of the total subscriptions of the limited partners, were paid to the general partner (CRC) in lieu of any allocation of overhead expenses. The fees were intended to compensate the general partner for its services, but were also used by the general partner to pay commission expenses totaling 8 percent of

90. In support of their claimed deduction of advanced royalties, petitioners rely solely on an opinion received from counsel to the effect that the note portions of the lease purchase prices paid in 1971 arguably could be deducted as advanced royalties. Although this opinion relies on the analysis propounded by Professor Fiedler in his article, "The Lessor, the Lessee and the Income Tax," *supra*, the opinion does not consider whether the transaction should be viewed as a sale. See Fiedler, "The Lessor, the Lessee and the Income Tax," *supra*, at 381-85. Apparently counsel assumed that CRC acquired mineral interests by lease, which we conclude on the facts is not correct for the 1972 transactions.

the total subscriptions. Respondent determined that the portion of the management fee which was used by CRC to pay commissions was a capital expenditure which could not be deducted by Coral I and Coral II.

Petitioners contend that the management fees constitute guaranteed payments which are deductible under section 707(c). Section 707(c) provides:

> (c) Guaranteed Payments.—To the extent determined without regard to the income of the partnership, payments to a partner for services or the use of capital shall be considered as made to one who is not a member of the partnership, but only for the purposes of section 61(a) (relating to gross income) and section 162(a) (relating to trade or business expenses).

Petitioners recognize, however, that guaranteed payments are not automatically deductible. We have recently held that guaranteed payments are deductible under section 707(c) only if such payments constitute a deductible ordinary and necessary business expense under sections 162 and 263. *Kimmelman v. Commissioner*, 72 T.C. 294, 304 (1979); *Cagle v. Commissioner*, 63 T.C. 86, 94-95 (1974), affd. 539 F. 2d 409, 414 (5th Cir. 1976).

Petitioners contend that the entire management fee paid by the limited partnerships constitutes an ordinary and necessary business expense. In support of their contention, petitioners assert that the management fee was used solely to compensate CRC for the services it performed as general partner. Petitioners dispute respondent's determination that a portion (8/18) of the management fee was used to pay commissions; they rely on the fact that the partnership agreements forbade the payment of commissions.

We cannot accept petitioners' contentions. The economic substance of these management fees, rather than their form and the form of the partnership agreements, governs for tax purposes. *Gregory v. Helvering*, 293 U.S. 465 (1935); *Commissioner v. Court Holding Co.*, 324 U.S. 331 (1945). The fact is that 8 percent of the limited partners' subscriptions, or 8/18 of the management fee, was used to pay commissions. Commissions are a nondeductible capital expenditure. *Woodward v. Commissioner*, 397 U.S. 572 (1970); *Vestal v. United States*, 498 F. 2d 487, 495 (8th Cir. 1974). Such commissions cannot be rendered deductible by the mere interposition of the general partner as a conduit. We sustain respondent's determinations with respect to this issue [91]

V. Abandonment Losses

Coral I, Coral II and CRC claimed abandonment losses as follows in 1972:

Coral I	$286,473
Coral II	288,674
CRC	18,533

Petitioners Brountas and CRC deducted their distributive shares of the abandonment losses claimed by Coral I and Coral II. These claimed losses arose from the alleged abandonment of the mineral leases with respect to prospects which had been tested unsuccessfully. Respondent disallowed these claimed losses in their entirety. Respondent determined, first, that claimed losses with respect to the cash portion of the lease purchase prices had been erroneously deducted. Second, respondent determined

91. Because of this conclusion, we do not reach any alternative arguments raised by the parties with respect to allocation of the management fees between ordinary and capital expenditures.

that no deductions were allowable with respect to the note portions of the lease purchase prices because the notes were shams and the deductions were improperly claimed.

Section 165(a) allows as a deduction any loss sustained during the taxable year and not compensated for by insurance or otherwise. In general, a deductible loss is sustained "during the taxable year in which the loss occurs as evidenced by closed and completed transactions and as fixed by identifiable events occurring in such taxable year." Section 1.165-1(d)(1), Income Tax Regs. Under certain circumstances, an "abandonment loss" deduction is allowed upon the sudden termination of usefulness of nondepreciable property.[92] In relevant part, section 1.165-2, Income Tax Regs., provides:

> § 1.165-2. Obsolescence of nondepreciable property.
>
> (a) *Allowance of deduction.* A loss incurred in a business or in a transaction entered into for profit and arising from the sudden termination of the usefulness in such business or transaction of any nondepreciable property, in a case where such business or transaction is discontinued or where such property is permanently discarded from use therein, shall be allowed as a deduction under section 165(a) for the taxable year in which the loss is actually sustained. For this purpose, the taxable year in which the loss is sustained is not necessarily the taxable year in which the overt act of abandonment, or the loss of title to the property, occurs.
>
> (b) *Exceptions.* This section does not apply to losses sustained upon the sale or exchange of property, losses sustained upon the obsolescence or worthless-

92. It is not disputed that the leases which were allegedly abandoned were nondepreciable property.

> ness of depreciable property, casualty losses, or losses reflected in inventories required to be taken under section 471. The limitations contained in sections 1211 and 1212 upon losses from the sale or exchange of capital assets do not apply to losses allowable under this section.

In this case, the partnerships and CRC established a policy for abandoning leaseholds which depended entirely upon a geological determination whether the lease in question had further geological merit. In the event that a test well was a dry hole which was plugged and abandoned, a geologist for CRC made a determination whether the lease should be abandoned or not. A lease was entirely abandoned when CRC or the partnerships ceased paying delay rentals for that lease. In some instances, however, a lease would be "partially abandoned." A "partial abandonment" could occur if the test well were productive or even if the well were a dry hole. In instances of partial abandoment, the geologist decided to retain a lease which was, in his view, partially worthless. The geologists would determine the percentage of the lease which was worthless and would inform CRC's accounting staff of the portion of the lease which had been abandoned. The accountants would then transfer the specified percentage of the purchase price indicated by the geologist from the capital account to the expense account as abandonment losses. Such abandonment losses, whether arising from the total or partial abandonment of the mineral lease, were then claimed as deductions on the partnerships' information returns. In any instance when all or a portion of the lease was retained, CRC would continue paying delay rentals on the entire lease.

We conclude that respondent correctly determined that the partnerships' method of reporting abandonment

losses was erroneous,[93] but we also conclude that a redetermination of the amount of allowable abandonment losses is necessary.[94] Several factual patterns are presented herein which lead to different results. Specifically, the timing of an abandonment loss depends on (a) the geological determination of worthlessness and (b) the payment of delay rentals.

We conclude, first, that when prospects were considered totally worthless by the partnerships on the basis of a geological determination (e.g., the test well as a dry hole which was plugged and abandoned) and the accountants were instructed to make no further delay rental payments, the partnerships were entitled to claim an abandonment loss when the due date for paying delay rentals was permitted to pass without payment. This conclusion is based on the legal test set forth in our decision in *Massey-Ferguson, Inc. v. Commissioner*, 59 T.C. 220, 225 (1972), where we noted:

> * * * this Court has stated that to be entitled to an abandonment loss, the petitioner must show an intention 'to abandon the property, coupled with an act of abandonment, both of which must be ascertained from all of the surrounding facts and circumstances.' *Boston Elevated Railway Co.*, 16 T.C. 1084, 1108 (1951), affd. 196 F. 2d 923 (C.A. 1, 1952) * * *.

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93. We have previously held that the nonrecourse notes were not shams, and this conclusion applies to the notes which were a portion of the lease purchase prices. Accordingly, we reject respondent's determination insofar as respondent concluded that no abandonment losses are allowed for the note portion of the lease purchase prices because the notes were shams.

94. A redetermination in accordance with the legal test set forth herein can be made by the parties on the basis of the partnerships' books and records.

See also *A.J. Industries, Inc. v. United States*, 503 F. 2d 660 (9th Cir. 1974). We believe that a geological determination of total worthlessness, coupled with the objective cessation of the payment of delay rentals, establishes that a mineral lease has been abandoned. There may be other ways in which an act of abandonment could have occurred—such as delivery to the lessor of a legally binding instrument disclaiming further rights under the lease—but we need not decide this because there is no evidence here of any irrevocable, definitive act of abandonment prior to letting the delay rental due date lapse without payment.

On the other hand, regardless of whether a test well was a dry hole, if the partnerships continued to pay delay rentals for a particular lease they were not entitled to claim an abandonment loss until there was an unequivocal act of abandonment such as letting a due date for such payments pass without payment.[95] In support of this conclusion, we rely on *A.T. Jergins Trust v. Commissioner*, 22 B.T.A. 551, 561-562 (1931), affd. on other issues, 288 U.S. 508 (1933), revg. 61 F. 2d 92 (9th Cir. 1932):

> The petitioner contracted to make the payments necessary to keep all of the leases in existence. * * * It may be that [the leases] were regarded as of little value but, if the parties were willing to continue to pay the rents and royalties necessary to keep such leases alive despite two dry holes, they evidence their opinion of some value. In a case such as this

95. This conclusion is in accordance with section 1.165-2(a), Income Tax Regs., which limits an abandonment loss to the time when business is discontinued or "where such property is permanently discarded from use therein * * *." Obviously, the partnerships had not discarded the mineral leases until they failed to pay delay rentals when due, so as to preserve their legal rights in these leases.

> it would be more reasonable to fix the date of worthlessness as being the date when the parties refused to pay further rents and royalties.

See also *Macon Oil and Gas Co. v. Commissioner*, 23 B.T.A. 54 (1931). The conclusion reached in *A. T. Jergins Trust* is entirely consistent with our decision in *Massey-Ferguson, Inc.*, since by payment of delay rentals the owner himself has indicated that value may remain in the property.

Our conclusion bars the "partial abandonment losses" which petitioners claimed. In a "partial abandonment," the partnership continued to pay delay rentals. Petitioners contend that each leasehold was divided into several mineral "properties" within the meaning of section 614(a) due to the stratification of mineral deposits below the surface.[96] Petitioners contend that if one mineral "horizon" were dry, that portion of a leasehold could be abandoned even if another strata yielded oil or gas. We disagree. The delay rentals which the partnerships paid retained their rights in the entire leasehold, and as long as the partnerships continued to pay such delay rentals they were not entitled to claim an abandonment loss of the mineral interests so retained. In other words, by paying the delay rentals the partnerships retained the right to develop and explore both the "dry" and "productive" strata, and they are not entitled to an abandonment loss when such rights are affirmatively retained. See *Louisiana Land & Exploration Co. v. Commissioner*, 7 T.C. 507 (1946), affd. 161 F. 2d 842 (5th Cir. 1947).

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96. Section 614(a) provides:

> For the purpose of computing the depletion allowance in the case of mines, wells, and other natural deposits, the term "property" means each separate interest owned by the taxpayer in each mineral deposit in each separate tract or parcel of land.

Our conclusion that the taxpayer had to cease payment of delay rentals in order to claim an abandonment loss is also supported by the Supreme Court's recent decision in *Thor Power Tool Co. v. Commissioner*, 439 U.S. 522, 545 (1979), affg. 64 T.C. 154 (1975), affd. 563 F. 2d 861 (7th Cir. 1977). Although *Thor Power Tool Co.* concerned the correct accounting procedures for inventory write down, the Court's conclusion is enlightening here:

> If this is indeed the dilemma that confronts Thor, it is in reality the same choice that every taxpayer who has a paper loss must face. It can realize its loss now and garner its tax benefit, or it can defer realization, and its deduction, hoping for better luck later. Thor, quite simply, has suffered no present loss. It deliberately manufactured its "excess" spare parts because it judged that the marginal cost of unsalable inventory would be lower than the cost of retooling machinery should demand surpass expectations. This was a rational business judgment and, not unpredictably, Thor now has inventory it believes it cannot sell. Thor, of course, it not so confident of its prediction as to be willing to scrap the "excess" parts now; it wants to keep them on hand, just in case. This, too, is a rational judgment, but there is no reason why the Treasury should subsidize Thor's hedging of its bets. There is also no reason why Thor should be entitled, for tax purposes, to have its cake and eat it, too.

Similarly, in this case the claimed partial abandonment losses are an attempt by the partnerships to have their cake and eat it. The partnerships desired to retain the mineral leases, and did so by paying delay rentals, but they also wanted to claim abandonment losses for at

least a portion of their lease costs. We conclude, however, that at least in the absence of any other affirmative and irrevocable act of abandonment, such abandonment losses cannot be claimed even if a geological determination is made that the lease should be entirely abandoned unless the due date for delay rental payments is permitted to pass without payment.

VI. Fraud

The final issue for decision is whether any part of petitioner CRC's underpayment of tax in 1972 was due to fraud. Section 6653(b) provides that if any part of an underpayment of tax is due to fraud, an addition to the tax equal to 50 percent of the total underpayment shall be imposed.

Respondent has the burden of proving fraud (section 7454(a)) and clear and convincing evidence is required to carry this burden. Rule 142(b), Tax Court Rules of Practice and Procedure; *Kashat v. Commissioner*, 229 F. 2d 282, 285 (6th Cir. 1956); *Otsuki v. Commissioner*, 53 T.C. 96, 106 (1969). The existence of fraud is a question to be determined upon consideration of the entire record. *Stratton v. Commissioner*, 54 T.C. 255, 284 (1970). To prove fraud, respondent must show that the taxpayer acted with the specific intent to evade a tax believed to be owing. *Cefalu v. Commissioner*, 276 F. 2d 122, 128-129 (5th Cir. 1960); *Estate of Temple v. Commissioner*, 67 T.C. 143, 159 (1976). Fraud is never presumed or imputed; mere suspicion of fraud is not sufficient. *Switzer v. Commissioner*, 20 T.C. 759, 765 (1953). Respondent, however, may meet his burden of proof through circumstantial evidence. *Powell v. Granquist*, 252 F. 2d 56, 61 (9th Cir. 1958).

Respondent's basic contention with respect to his determination of the additions to tax for fraud is that CRC

created and employed a sham transaction. Respondent argues that the entire structure of the 1972 drilling fund was conceived and implemented by CRC with the intent to evade taxes known to be owing by Dauber and Soter. In essence, as we noted previously, the gravamen of respondent's position is that CRC's entire program was a tax gimmick and a fraud.

We believe that respondent's determination of an addition to tax for fraud because of the alleged sham nature of these transactions is devoid of merit. We have concluded that CRC's drilling program had economic substance, that all negotiations with respect thereto were conducted at arm's length, that the consideration which was exchanged in the transaction was within a reasonable range of commercial practice, and that petitioners' tax treatment of the nonrecourse notes was fundamentally sound. The only concrete evidence of fraud which respondent presented came from a witness, Scoggins, who contradicted his own prior sworn testimony and whom we found to be lacking in credibility. The alleged fraud and sham arrangement which respondent contends CRC perpetrated did not exist; rather, CRC entered into bona fide transactions with independent oil and gas drilling operators in a program for the exploration and development of mineral resources. To be sure, tax considerations played a dominant role in the structure which CRC employed in its program, but tax planning is not fraud. *Frank Lyon Co. v. United States,* 435 U.S. 561 (1978).

Nonetheless, because we have sustained respondent's determinations with respect to several of the issues in this case, we must consider whether any part of petitioner CRC's underpayment of tax was due to fraud. We are convinced that such was not the case.

First, we sustained respondent's disallowance of CRC's claimed deduction for advanced royalties in 1972.

These alleged advanced royalties were the note portions of the lease purchase price; petitioners contended that these amounts were deductible in 1972. In support of their position, petitioners relied on the opinion of counsel to that effect. While we disagreed with petitioners, there is no evidence in the record that CRC claimed this deduction with the intent to evade tax. CRC's good faith reliance upon the opinion of counsel indicates to us that with respect to the claimed deductions for advanced royalties there was no fraud. See *Rice v. Commissioner*, 14 T.C. 503 (1950).

Second, we sustained respondent's determination that CRC incorrectly claimed abandonment losses. CRC claimed that it was entitled to deduct partial abandonment losses, while we concluded that CRC was entitled to deduct abandonment losses for the various mineral leases only at the time that such leases were completely abandoned. Perhaps Dauber and Soter, both tax lawyers, should have known that such partial abandonment losses were impermissible, but there is no evidence in the record that this deduction was claimed with an intent to evade a tax believed to be owing. Respondent has failed to convince us that the abandonment loss deductions were fraudulently claimed.[97]

To reflect the foregoing,
appropriate orders will be entered.

97. We note that respondent also incorrectly determined the amount of abandonment losses which petitioners are entitled to deduct, and a redetermination of these deductions in light of our opinion will be necessary.

74 T.C. No. 78

UNITED STATES TAX COURT

PAUL P. BROUNTAS AND LYNN T. BROUNTAS,
Petitioners

v.

COMMISSIONER OF INTERNAL REVENUE,
Respondent

CRC CORPORATION,
Petitioner

v.

COMMISSIONER OF INTERNAL REVENUE,
Respondent

Docket Nos. 8231-76, 8497-76, 8698-77, 6255-78

Filed August 13, 1980.

Held, the term "disposition" as used in section 1.636-1 (c)(1), Income Tax Regs., includes abandonments of mineral properties burdened by section 636 production payments. On the facts, a constructive disposition for gain purposes occurred when all the wells on leases in a cross-collateralized package of leases proved to be dry holes. *Held, further*, under respondent's concession, the gain is section 1231 gain if the requisite holding period has been met and, if not, is ordinary income.

Thomas B. Rutter, for the petitioners.

Bernard B. Nelson, Richard A. Hartnig, Robert T. Hollohan, Paul F. Kugler, James F. Malloy, Michael K. Phalin and *Richard B. Weinstein*, for the respondent.

SUPPLEMENTAL OPINION

HALL, *Judge*: On December 26, 1979, we filed our original opinion (73 T.C. 491) in this case in which we made exhaustive findings of fact which we adopt for purposes of this supplemental opinion. However, the complex nature of the transactions which underlie this case warrants a brief recital of the facts pertinent to this supplemental opinion.

CRC, either on its own behalf or on behalf of a limited partnership (such as Coral I or Coral II), entered into various agreements with a given operator. These agreements (which generally consisted of (1) a Lease Purchase and Turnkey Drilling Agreement, (2) a Loan Agreement, (3) a Promissory Note ("Note"), (4) a Mortgage, Deed of Trust, Assignment of Security Interest ("Mortgage"), and (5) a Joint Venture Agreement) would pertain to a "package" of prospects submitted by an operator. A package usually involved two or more (typically three) noncontiguous oil and gas prospects to be drilled by a single operator. Participation in the various packages was generally shared by many limited partnerships. A limited partnership (such as Coral I) invested in many packages, receiving a small percentage interest in each, in order to obtain diversification.

The above-listed agreements were entered into by the operators and, on behalf of the limited partnerships and CRC (hereinafter collectively referred to as "Investors") by CRC. Typically the five agreements were executed simultaneously.

The Lease Purchase and Turnkey Drilling Agreement provided, first, for the transfer from the operator to the Investors of the operator's interest in the oil, gas and/or mineral leases with respect to the prospects (usually three) in the package. A price ("lease purchase price") was stated for each lease in the package. Second, the operator agreed to drill a test well on each prospect at a specified location to a specified depth. This obligation was absolute, regardless of circumstances or difficulties, foreseen or unforeseen, which might be encountered. The operator was obligated to furnish all equipment, drilling rigs, drilling mud, location preparation, etc. necessary for the drilling of the well. If any well were a dry hole, the operator was obligated to plug the hole and restore the surface. In consideration for this no-out turnkey drilling agreement, which applied to all the prospects in a package, the Investors promised to pay the operator a single amount ("drilling contract price").

The Loan Agreement provided that the operator/lender would lend to the partnership or CRC an agreed-upon sum to be used by the partnership or CRC to pay a portion of both the lease purchase price and the drilling contract price under the related Lease Purchase and Turnkey Drilling Agreement.[1] The agreed-upon sum was usually 60 percent of the combined lease acquisition cost and turnkey drilling cost, although the percentage varied in some packages. For example, if the total cost of the lease purchase and the drilling contract were $100,000, the loan (hereinafter the "note portion") would be $60,000; the remaining $40,000 would be the Investors' contribution (the "cash portion").

The debt arising out of the Loan Agreement was evidenced by the Note and secured by the Mortgage.

1. The total amount borrowed to purchase the lease and to secure the drilling obligation was represented by a single note.

The Note was payable solely from production, if any, from the prospect or from certain other prospects (usually two) with respect to which the note was cross-collateralized.

The nonrecourse Notes constituted "production payments" within the meaning of section 636 [2] and section 1.636-3(a), Income Tax Regs., and, consequently, they are treated for tax purposes as loans from the operators to the partnerships or CRC. The portion of the nonrecourse Notes allocable to the lease purchase price is a retained production payment, see sec. 1.636-1(a)(1)(i), Income Tax Regs., and is treated for purposes of subtitle A of the Internal Revenue Code as a purchase money mortgage. Sec. 636(b). The portion of the nonrecourse Notes allocable to the no-out turnkey drilling contract is a carved-out production payment, see sec. 1.636-1(a)(1)(i), Income Tax Regs., and is treated for purposes of subtitle A of the Internal Revenue Code as a mortgage loan on the burdened property. Sec. 636(a).

The Loan Agreement also provided the operator/lender an option to enter into a completion joint venture with the borrower (*i.e.*, the Investors) within twenty-four hours after a well on a prospect had been logged and tested.

All negotiations between CRC and the operators were at "arm's length." The terms of the total contract were fair and reasonable. The operators received the cash portion of the total contract price, plus a nonrecourse note for the remainder of the contract price, and the completion option; in return, the operators sold the leases to the Investors and were obligated, on a no-out basis, to drill the test wells, and if a completion were attempted, to pay all completion costs plus reimburse the Investors

2. All statutory references are to the Internal Revenue Code of 1954, as in effect during the years in issue.

for their lease purchase price plus their tangible equipment.

In 1972 Coral I and Coral II participated in twenty-four oil and gas drilling packages. Eleven of these packages resulted in all dry holes which were plugged. As an individual investor, CRC participated in twenty-eight packages in 1972. Thirteen of these resulted in all dry holes which were plugged. Additionally, in many other packages one or more wells were plugged, although in all of the other packages at least one well was completed as a producing well.

Each Coral partnership and CRC validly elected, pursuant to section 263, to deduct the intangible drilling costs. The amount of the intangible drilling and development costs was the aliquot share of the total price of the turnkey drilling contracts (cash and note portions) for the packages in which Coral I, Coral II and CRC had direct interests. The portion of the total cost of the Lease Purchase and Turnkey Drilling Contracts which was allocable to acquisition of the leases was not deducted as an intangible drilling and development cost.

Coral I, Coral II and CRC claimed abandonment losses in 1972 arising from the alleged abandonment of the mineral leases with respect to prospects which had been tested. The value of the losses was determined by the lease purchase prices paid to the operators.[3] We held that under the circumstances the abandonment losses of capitalized leasehold acquisition costs were allowable only when the due date for paying delay rentals passed without payment.

When all the leases for the prospects in a package were entirely "abandoned", the nonrecourse Note which was secured by the leaseholds was viewed as worthless

3. The lease purchase price consisted of cash and the portion of the nonrecourse note related to the lease purchase.

by CRC and the partnerships. Thus, as long as CRC continued paying delay rentals with respect to at least one lease in a package in which all the prospects were dry holes, the Note with respect to the package would not be "canceled."

The sole issues for decision in this supplemental opinion are the amount, timing and character of petitioners'[4] 1972 and 1973 income derived from the worthlessness of nonrecourse notes used to finance oil and gas drilling ventures.

The formulation of respondent's position on these issues has taken a tortuous path. In his statutory notices, respondent's main line of attack was to categorize the nonrecourse notes as shams, thereby eliminating the income and deduction consequences of the notes. In the alternative, respondent argued that all the nonrecourse notes outstanding as of December 31, 1972, were forgiven during 1973, thereby giving rise to cancellation of indebtedness income. Under this alternative theory respondent determined petitioners had received the following amounts of ordinary income in 1973:

Petitioner	*Coral I*	*Coral II*	*CRC (individually)*
Brountas	$ 5,547.90	—0—	—0—
CRC	27,895.00	$27,871.00	$399,461.00

Respondent's original briefs and his supplemental briefs indicate that he has abandoned the position asserted in his statutory notices. Rather, respondent now asserts that petitioner should recognize income when the

4. Unless otherwise indicated, the term "petitioners" is used herein to refer to the partnerships in which petitioners (CRC and Brountas) were limited partners as well as to CRC in its individual capacity (with respect to the transactions in which it participated directly).

last well in each package of prospects has been plugged.[5] This assertion is premised on alternative, but related, theories of income recognition. The primary argument is that the plugging of all the wells in a package constitutes a constructive abandonment, *i.e.*, a disposition, of the mineral leases burdened by the nonrecourse loans.[6] Respondent contends that under the facts of this case the worthlessness of the leases securing the nonrecourse notes makes any subsequent acts of abandonment superfluous and, consequently, the worthless leased properties are effectively abandoned when the last well in each package has been plugged. Accordingly, respondent argues that the tax consequences of the constructive abandonment are dictated by sections 1.636-1(c)(1) and (2), Income Tax Regs., and sections 1001 and 61(a)(3) of the Internal Revenue Code. In the alternative, respondent claims that petitioners must recognize cancellation of indebtedness income under section 61(a)(12) when the last well in each package was plugged because, under the "all events" test of accrual accounting, the nonrecourse notes became worthless at that time.[7]

Petitioners reported income from the worthlessness of the nonrecourse notes at the time they ceased paying delay

5. Because each of the notes in a given package is cross-collateralized, the possibility of repayment on each of those notes exists until the last well in the package has been plugged and abandoned.

6. This constructive abandonment is in contradistinction to the formal abandonment, *i.e.*, cessation of delay rentals, giving rise to petitioners' abandonment losses.

7. Respondent has not indicated how much income would be recognizable using either method. The amount, however, would presumably be easily calculable as part of the Rule 155 computation required under this Court's Rules of Practice and Procedure because there is no apparent dispute between the parties as to when each package of prospects was plugged.

rentals with respect to all the prospects in a package. Petitioner CRC reported such income from its direct investments as ordinary while limited partners, such as petitioner Brountas, reported it as capital gains under the principle of *Stackhouse v. United States*, 441 F. 2d 465 (5th Cir. 1971).[8]

At the threshold, petitioners raise two procedure-related issues. First, petitioners contend that respondent should bear the burden of proof with respect to the "income" issues because respondent's alternative determination in his statutory notice was without rational foundation. See *Helvering v. Taylor*, 293 U.S. 507 (1935). In support of their position petitioners argue that the facts of this case, as evidenced by petitioners' records available to respondent prior to trial and as confirmed by our findings of fact in the original opinion, indicate that many of the nonrecourse notes were paid off subsequent to December 31, 1972. Consequently, petitioners assert that respondent's determination in the statutory notices that all nonrecourse notes outstanding as of December 31, 1972, were canceled or forgiven in 1973 was erroneous and arbitrary within the meaning of *Helvering v. Taylor*.

Whether or not we were to agree with petitioners that the burden of proof shifted to respondent, the result herein would be the same. The evidence introduced during trial pointed clearly to the findings of fact set forth in our original opinion. Under these circumstances, we would not hesitate to find that respondent sustained his burden of proving these facts.

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8. Petitioners' theory for income recognition does not involve section 61(a)(12) which they argue is not applicable. Rather petitioners argue that they must recognize income pursuant to sections 752(b) and 731 when the nonrecourse note is canceled. According to petitioners this cancellation occurs at the same "objective" point in time used by this Court for abandonment loss recognition, *i.e.*, the lapse of the delay rentals.

The second matter raised by petitioners is the effect to be given to their "method of accounting" for income from the worthlessness of the nonrecourse notes. Petitioners contend that the procedure which they followed for reporting income, *i.e.*, to recognize income when delay rentals lapsed, constitutes a "method of accounting" within the meaning of sections 1.446-1(a)(1) and (2), Income Tax Regs.[9] Petitioners further contend that this "method

9. Sections 1.446-1(a)(1) and (2) provide:

(a) *General rule.* (1) Section 446(a) provides that taxable income shall be computed under the method of accounting on the basis of which a taxpayer regularly computes his income in keeping his books. The term "method of accounting" includes not only the over-all method of accounting of the taxpayer but also the accounting treatment of any item. Examples of such over-all methods are the cash receipts and disbursements method, an accrual method, combinations of such methods, and combinations of the foregoing with various methods provided for the accounting treatment of special items. These methods of accounting for special items include the accounting treatment prescribed for research and experimental expenditures, soil and water conservation expenditures, depreciation, net operating losses, etc. Except for deviations permitted or required by such special accounting treatment, taxable income shall be computed under the method of accounting on the basis of which the taxpayer regularly computes his income in keeping his books. For requirement respecting the adoption or change of accounting method, see section 446(e) and paragraph (e) of this section.

(2) It is recognized that no uniform method of accounting can be prescribed for all taxpayers. Each taxpayer shall adopt such forms and systems as are, in his judgment, best suited to his needs. However, no method of accounting is acceptable unless, in the opinion of the Commissioner, it clearly reflects income. A method of accounting which reflects the consistent application of generally accepted accounting principles in a particular trade or business in accordance with accepted conditions or practices in that trade or business will

of accounting" should be accepted by respondent as clearly reflecting income because petitioners have consistently followed this method and because it does not distort income. See sec. 1.446-1(a)(2), Income Tax Regs.

Respondent conceded that petitioners' reporting procedure constitutes a "method of accounting." Nevertheless, respondent argues that the method of accounting employed by petitioners does not clearly reflect income and, therefore, is not an acceptable method of accounting. Sec. 446(b); sec. 1.446-1(a)(2), Income Tax Regs.

It is well-settled that an erroneous method of accounting does not become acceptable solely upon the consistent use over an extended period of time. *Dearborn Gage Co. v. Commissioner*, 48 T.C. 190 (1967). It is similarly well-settled that respondent cannot require a taxpayer to change his accounting method to one which is unacceptable or wrong. See, *e.g.*, *Harden v. Commissioner*, 223 F. 2d 418 (10th Cir. 1955).

The determination of which proposed "method of accounting", petitioners' or respondent's, clearly reflects petitioners' income depends on when and the extent to which the nonrecourse notes, cancelled by virtue of their worthlessness, were required to be included in income. The resolution of that question depends upon the outcome of the legal issues to be decided herein.

That brings us to the basic issues to be decided herein, namely, the amount, the timing and the character of the income to be recognized by petitioners when their nonrecourse notes became worthless. We previously held that petitioners abandoned a lease for purposes of recognizing a loss when the due date for paying the delay

9. (Cont'd.)

ordinarily be regarded as clearly reflecting income, provided all items of gross income and expenses are treated consistently from year to year.

rental on such lease passed without payment. The nonrecourse notes in issue in this case (covering the lease purchase price and the contract drilling price) are "production payments" within the meaning of section 636 and section 1.636-3(a), Income Tax Regs. The amount of an abandonment loss realized on the abandonment of a purchased lease is determined in accordance with section 1.636-1(c)(2), Income Tax Regs., which provides in pertinent part as follows:

> In the case of the expiration, termination, or abandonment of a mineral property burdened by a production payment treated as a loan pursuant to this section, for purposes of determining the amount of any loss under section 165 with respect to the burdened mineral property the adjusted basis of such property shall be reduced (but not below zero) by an amount equal to the outstanding principal balance of such production payment on the date of the expiration, termination or abandonment. * * *

In this case, for example, if petitioners paid $100,000 for a lease, consisting of $40,000 cash and a $60,000 note (which is a production payment treated as a purchase money mortgage loan under section 636(b)), the amount of petitioners' abandonment loss would appear to be $40,000 (adjusted basis of $100,000 less outstanding principal balance of production payment included in the basis of $60,000).[10] However, respondent contends that the apparent loss cannot be recognized at the time a particular lease in a package is abandoned because all the prospects in a package are cross-collateralized and we cannot know the amount of the outstanding principal balance of the

10. Respondent concedes on brief (Opening Brief pp. 16 and 43, *et seq.*) that this loss is an ordinary loss (either because the lease qualifies as § 1231 property that has been sold or exchanged or because the leases are inventory property).

production payment burdening the property until the note (including both the lease purchase portion and the drilling contract portion) is canceled. Thus, the abandonment loss cannot be calculated until all the leases in a package are abandoned. We cannot read section 1.636-1(c)(2), Income Tax Regs., literally in the case of a cross-collateralized lease or we would have to hold either that the production payments on *all* the leases in a package would reduce basis as to each lease, thereby eliminating any loss, or there would be no reduction in basis as to the first two leases, and there would be a gain on the abandonment of the last lease (assuming three leases in the package) still burdened with a production payment obligated to pay all the unpaid notes. We find the most logical result is to read the regulation to mean that the "outstanding principal balance of such production payment" applies only to the production payment included in the basis of the lease. Under such an interpretation, the ordinary loss recognized on the abandonment of a lease is recognized at the time of such abandonment, determined without regard to the status of the other leases in the package. The time of such abandonment, as we have held, is when an affirmative act of abandonment occurs, in this case when a delay rental due date passes without payment.

In the case of the drilling contract portion of the deal, the petitioners recognize *gain* on abandonment. Petitioners agreed to pay an operator a drilling contract price consisting of a cash portion and a note portion. The note is nonrecourse and secured solely by production from a package of prospects; in our prior opinion we held that the contract drilling portion of the note is a carved-out production payment under section 636(a), treated as a mortgage loan. We further held that the face amount of the note was fully includible in the partners' partnership

bases as a liability under section 752, and that the partnerships are entitled to deductions for intangible drilling and development costs equal to the face amount of the contract drilling price (cash and note portion). As a result in most, if not all, cases the partners have a zero basis in their partnership interests attributable to the contract drilling price. CRC also would have a zero basis in its interest attributable to the contract drilling price.

The first question we must answer is under what theory do petitioners recognize gain on the abandonment of all the leases in a package. As we previously noted, respondent's primary argument is that the abandonment of all the leases in a package was a disposition of such leases under section 1.636-1(c)(1), Income Tax Regs., and gain is recognized in accordance with such regulation. Respondent's alternative argument is that petitioners recognize cancellation of indebtedness income under section 61(a)(12) when the last well in each package is abandoned because the nonrecourse notes became worthless at that time. Petitioners contend that section 1.636-1(c)(1), Income Tax Regs., does not apply in this case. We agree with respondent that gain is recognized here under section 1.636-1(c)(1), Income Tax Regs., and therefore do not reach the issue of cancellation of indebtedness income.

Section 1.636-1(c)(1), Income Tax Regs., provides in pertinent part as follows:

> In the case of a sale or other *disposition* of the mineral property burdened by a production payment treated as a loan pursuant to this section [section 636], there shall be included in determining the amount realized upon such disposition an amount equal to the outstanding principal balance of such production payment on the date of such disposition. * * * [Emphasis added.]

Section 1.636-1(c)(2), Income Tax Regs., quoted in relevant part above, provides that in the case of "expiration, termination, or abandonment" of such a property, for purposes of determining any loss under section 165, adjusted basis shall be reduced (but not below zero) by the amount of the then outstanding principal balance of such production payment. Petitioners contend that *gain* on an abandonment simply isn't covered by the Regulations. They contend that an abandonment cannot be a disposition for the purpose of section 1.636-1(c)(1), Income Tax Regs., because abandonments are separately covered under section 1.636-1(c)(2), Income Tax Regs. We disagree.

While the Regulations appear to be most inarticulately drawn, we conclude that an abandonment at a *gain* is covered by section 1.636-1(c)(1), Income Tax Regs., while abandonment at a loss is covered by section 1.636-1(c)(2), Income Tax Regs. First, the statute itself requires such a result. In section 636, production payments of the types involved in this case are treated as mortgage payments. *Crane v. Commissioner*, 331 U.S. 1 (1947), teaches that on a disposition of a property encumbered by a nonrecourse mortgage, the amount of the mortgage must be included in the amount realized. Section 1.636-1(c)(1), Income Tax Regs., is no more than a restatement of the *Crane* principle. See *Freeland v. Commissioner*, 74 T.C. — (1980).

Second, the legislative history requires that we interpret "disposition" to include abandonment. Addressing itself to the disposition of the burdened mineral properties, the Senate Finance Committee stated:

> It is contemplated that the regulations issued on this provision will make it clear that on a sale or other disposition (*including an abandonment*) of a mineral property burdened by a production payment carved

> out by the taxpayer, any unpaid balance of the production payment will be taken into account in computing the gain or loss on the sale or other disposition. S. Rep. No. 91-552, 91st Cong., 1st Sess. (1969), 1969-3 C.B. 423, 541. [Emphasis added.]

We conclude that section 1.636-1(c)(1), Income Tax Regs., promulgated under the express authority of section 636(c), includes abandonments in the term "disposition", and that section 1.636-1(c)(2), Income Tax Regs., is merely an exception to the general rule in subsection (c)(1), an exception applicable only when an abandonment results in a loss.

Third, common sense requires that we include abandonment at a gain under section 1.636-1(c)(1), Income Tax Regs. There is no logical reason for excluding from treatment under section 636 only mineral property burdened by a production payment which is abandoned at a gain.

The second question is *when* petitioners recognize income. That in turn depends on when the investors lost their collateral (leases) for their notes. We held that for purposes of recognizing a loss on abandonment of a lease with respect to the lease purchase price, the abandonment occurred when petitioners permitted the due date for paying delay rentals on the lease to pass without payment. Petitioners contend that, consistent with that position, they abandoned the collateral for the contract drilling price for tax purposes only when they permitted the due date for paying delay rentals on the last of the prospects in a package (those prospects cross-collateralizing the note) to expire without payment. At that point there was no means of paying the note and the note became worthless. Respondent asserts that for purposes of recognizing gain there was a "constructive abandonment" of the collateral

and the note became worthless when the last test well in each package was plugged and abandoned because at that point the leases became worthless, all significant possibility of payment on the nonrecourse notes disappeared and the notes were effectively canceled. Respondent adds that petitioners cannot indefinitely delay recognition of income by the simple expedient of paying nominal delay rentals.

Here the evidence does not suffice for us to find as a fact that petitioners continued their delay rentals purely for the purpose of delaying recognition of income on the disposition of their mineral properties. Petitioners contend that they based the continued payment of delay rentals on geological determinations of whether the leases had further geological merit. However, the delay rentals were nominal in amount, and the record discloses no instance in which another well was drilled on a prospect after a dry hole had been drilled, nor was such a prospect ever farmed out, nor did it ever produce any mineral.

Moreover, we have found as a fact that "[i]f a prospect yielded a dry hole, both * * * equipment and the mineral interest were of minimal, if any, value." *Brountas v. Commissioner, supra* at 518, n. 38. Under the circumstances, we need not determine the reason for continue payment of delay rentals, for we believe that once the last dry hole in a package was drilled, the prospects under our facts ceased to have any cognizable value, and that for reasons stated below this loss of value required the recognition of the gain on the drilling contracts. Certainly it would be theoretically possible for a hole to be dry and yet to yield geological information warranting a new try on the same prospect. However, this never in fact happened on any of the leases here in issue. We find as a fact here that in each lease before us the drilling of a dry hole eliminated any cognizable value of the property as a mineral prospect.

The issue of the timing of recognition of gain on relief of "indebtedness" under section 1.636-1(c)(1), Income Tax Regs., must be distinguished from the issue of the timing of an abandonment loss under section 1.636-1 (c)(2), Income Tax Regs. While, as we have held, recognition of the loss must await the objective act of abandonment, as by letting a lease lapse, we do not believe the same standard applies to the issue of gain from relief of indebtedness. Rather, we believe that the moment it becomes clear that the "loan" will never have to be paid, the "loan" must be viewed as having been discharged. For this purpose, the test must be the practical one of worthlessness of the debt—the point at which a creditor could deduct a bad debt is not when it is absolutely impossible that it could be repaid, but when only an incorrigible optimist would expect repayment. *Ramsay Scarlett & Co. v. Commissioner*, 61 T.C. 795, 811 (1974), affd. 521 F. 2d 786 (4th Cir. 1975). Likewise here, we do not believe respondent must wait for his recapture until delay rentals fall due unpaid, but only until the last well from which potential production could repay the debt is a dry hole or runs dry, or until it is otherwise clear as a practical matter to all but the incorrigible optimist that no payment, or further payment, is forthcoming.

In the case of the abandonment loss, a taxpayer believing the lease to be worthless has it in his own hands to nail down his loss by an affirmative act of abandonment. We do not believe that the law gives him the same freedom to stave off recapture of his deductions beyond the point of practical worthlessness of the debt which generated the basis for his write-off. Such freedom would permit too easy avoidance of the revenue laws. Nor, should he be an incorrigible optimist and continue payment of delay rentals past the point of objective futility, should he be treated better tax-wise than the investor who does the

same for purely tax reasons. Accordingly, we do not find it necessary here to determine whether petitioners' continued payment of delay rentals was tax motivated. It was objectively futile, and we hold that a constructive disposition of each mineral prospect occurred for purposes of section 1.636-1(c)(1) as soon as all prospects securing the "mortgage loan" proved to be dry holes or (in cases where production was found) ran dry.

The last question we must answer is the *character* of the gain realized upon the abandonment of all the leases in a package. Here we are faced with a most extraordinary circumstance. Petitioner CRC reported the gain as ordinary income on the theory that an abandonment was not a sale or exchange, and does not here contend that this was error. Respondent contends that section 1231 (covering for the years in issue gains on sales or exchanges of property held for more than six months and used in a trade or business) applies to the leases abandoned in this case if they had been held for over six months, citing Rev. Rul. 68-226, 1968-1 C.B. 362. With petitioners accepting ordinary income treatment and respondent determining the gains are capital gains where the holding period requirement has been met, there is no controversy we can adjudicate. We accept respondent's conclusion, which may reduce petitioners' liabilities, without reaching its merit. The character of the gain realized by CRC and the partnerships is therefore long term capital gain or ordinary income depending on the holding period.[11]

11. In our prior opinion we held that the operators received from the partnerships consideration consisting of cash, nonrecourse notes and completion options in exchange for leases and drilling obligations. With respect to the tax consequences accompanying the grant of the completion options, respondent did not contend that this was a taxable event to the petitioners nor did petitioners contend that they were entitled to deduct any additional intangible

Appropriate orders will be entered.

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11. (Cont'd.)

drilling costs or to increase their bases in the leases by virtue of the grant of the options. We requested both parties to brief the question of whether the option was a taxable event. After a review of those briefs and the authorities cited therein, we conclude that the grant of the option is devoid of immediate tax consequences to petitioners. Sec. 1.421-6, Income Tax Regs. Whatever income would be generated by the completion options upon their grant, lapse or exercise, would be correspondingly offset by increases in partnership bases and intangible drilling cost deductions.